Plains Exploration & Production Company 2009 Annual Report

PXP

Company Profile

PXP is committed to providing a work place that protects the health and safety of our employees and the communities surrounding our operations, and adhering to high standards of environmental quality.

We strive to lead the industry not only in compliance, but in innovation that sets new standards. With an award-winning commitment to safety and environmental excellence, industry-leading operational expertise, and collaborative approach, PXP has achieved great success in challenging technical and regulatory environments.

Through PXP's charitable and business contributions, the Company prides itself on being a leading corporate citizen. Our charitable contributions are geared towards supporting programs that improve the quality of life for citizens of the communities in which PXP operates.

We are an independent oil and gas company engaged in the activities of acquiring, developing, exploring and producing oil and gas properties primarily in the United States and were formed as a Delaware corporation in 2002.

Our oil and gas operations are concentrated onshore California, offshore California, the Gulf Coast Region, the Gulf of Mexico, the Mid-Continent Region and the Rocky Mountains. We also have an interest in an exploration block 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 believe our balanced portfolio of assets, our 2009 deleveraging transactions and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities.

Financial Highlights

(in thousands, except per share and percentage information)	**2009**	2008[1]	2007[2]	2006	2005
Reserve Data:					
Total oil reserves (barrels)	**214,030**	177,707	436,533	333,217	356,333
Total gas reserves (Mcf)	**873,108**	686,357	1,519,976	110,922	267,921
Total barrels of oil equivalent (BOE)	**359,548**	292,100	689,862	351,704	400,987
Percentage proved developed volume	**64%**	72%	51%	52%	67%
Estimated future net cash flows	**$4,542,695**	$ 2,489,612	$18,042,121	$5,652,412	$6,772,811
Standardized measure	**$2,224,839**	$ 1,136,374	$ 7,623,323	$2,510,663	$3,082,166
Percentage proved developed present value	**80%**	96%	67%	68%	77%
Operating Data:					
Oil production (barrels)	**17,560**	20,294	18,124	18,975	18,671
Average oil price (per barrel)[3]	**$ 51.43**	$ 87.05	$ 61.60	$ 55.62	$ 46.76
Gas production (Mcf)	**78,184**	79,254	29,312	20,629	29,359
Average gas price (per Mcf)[3]	**$ 3.72**	$ 8.05	$ 5.68	$ 6.73	$ 7.15
BOE production	**30,591**	33,503	23,010	22,413	23,564
Average BOE price[3]	**$ 39.25**	$ 72.03	$ 56.12	$ 53.76	$ 45.96
Production expense per BOE	**$ 14.03**	$ 18.91	$ 18.25	$ 14.49	$ 12.10
Selected Financial Data:					
Total revenue	**$1,187,130**	$ 2,403,471	$ 1,272,840	$1,018,503	$ 944,420
Income (loss) from operations[4]	**$ 282,133**	$(2,627,413)	$ 419,634	$1,348,450	$ 343,700
Income (loss) before cumulative effect of accounting change	**$ 136,305**	$ (709,094)	$ 158,751	$ 599,710	$ (214,012)
Cumulative effect of accounting change, net of income tax	–	–	–	$ (2,182)	–
Net income (loss)	**$ 136,305**	$ (709,094)	$ 158,751	$ 597,528	$ (214,012)
Diluted income (loss) per share					
Before cumulative effect of accounting change	**$ 1.09**	$ (6.52)	$ 1.99	$ 7.67	$ (2.75)
Cumulative effect of accounting change	–	–	–	$ (0.03)	–
Net income (loss) per share	**$ 1.09**	$ (6.52)	$ 1.99	$ 7.64	$ (2.75)
Weighted average shares outstanding					
Basic	**124,405**	108,828	78,627	77,273	77,726
Diluted	**125,288**	108,828	79,808	78,234	77,726
Total assets	**$7,734,731**	$ 7,111,915	$ 9,693,351	$2,463,228	$2,741,942
Long-term debt	**$2,649,689**	$ 2,805,000	$ 3,305,000	$ 235,500	$ 797,375
Total stockholders' equity	**$3,198,981**	$ 2,377,280	$ 3,338,247	$1,130,683	$ 718,337

[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] Average realized sales price before derivative transactions.

[4] We are required to perform a full cost ceiling test each quarter. At December 31, 2008, our capitalized costs of 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

PXP had a remarkable year in 2009. We continued implementing our value creation model capable of efficiently growing production and reserves. As our industry faced commodity price volatility and significant economic uncertainty throughout the year, we applied our experience, remained focused on our long-term growth platform and executed our strategic plans. The quality of our people and portfolio continue to standout as we reported significant progress in growing production and reserves as well as lowering costs, strengthening liquidity and expanding our resource potential during today's challenging environment.

Despite the turbulence in the commodity and financial markets, we produced solid results. Full-year average daily sales volumes increased 8% compared to 2008, excluding the impact of our 2008 divestments, and proved reserves increased 23% over 2008 year-end amounts. Our Flatrock development in the Gulf of Mexico and our Haynesville Shale project in North Louisiana were significant contributors to the increases. In addition, our Gulf of Mexico exploration program, a cornerstone to our strategy of adding to our future development project inventory, delivered a number of discoveries.

In California, while drilling activity was less than in previous years, PXP maintained an active development program onshore and made progress on several permitting issues. California onshore is PXP's largest asset area with proved reserves of approximately 204 million barrels of oil equivalent at year-end 2009. With a multi-year inventory identified in the San Joaquin Valley, the Arroyo Grande Field and the Los Angeles Basin, these asset areas will sustain years of drilling providing future reserves, production and free cash flow.

The Haynesville Shale drilling results have been outstanding. Fourth quarter average daily production of approximately 75 million cubic feet equivalent net to PXP represents a 436% increase from the first quarter 2009; and production is expected to continue to increase to approximately 125 million cubic feet equivalent net per day by year-end 2010. At year-end 2009, PXP's net acreage position was over 111,000 acres; and with approximately 1,400 potential net well locations, this asset area is expected to be a significant driver of future production and reserve growth.

In the Gulf of Mexico, we viewed 2009 as a year of identification and look to 2010 as the year of confirmation. Our Flatrock development contributed meaningful sales volume growth during the year; and our exploration program has been dynamic. PXP announced Friesian delineation drilling success and participated in discoveries at Davy Jones, Lucius and Blueberry Hill. For Friesian, early stage commercialization initiatives for production are under study. The Lucius discovery announced in December 2009 was followed by a successful appraisal well in late January 2010 which confirmed a major oil discovery. Appraisal and further drilling continues at Davy Jones and Blueberry Hill. These projects have the potential to provide significant incremental future production and reserve growth.

In the Texas Panhandle, South Texas and Gulf Coast asset areas, PXP focused on technical evaluations, leasing, permitting and other related activities in preparation for more drilling activity. In the Texas Panhandle, we look forward to drilling our Granite and Atoka Wash positions. In the Gulf Coast, we received the necessary permits to drill a new prospect, and in South Texas, we drilled several successful infill development wells and high-graded the drilling inventory.

Uncertain financial conditions and a deteriorated commodity price environment affected our industry during 2009 and continue to be at the forefront of our planning as we move into 2010. We are mindful of our need to protect our balance sheet, liquidity and operating efficiencies as we continue to pursue our balanced operational strategy. During 2009, PXP monetized $1.1 billion in commodity derivative gains which accelerated cash receipts, entered into 2010 crude oil derivative positions and acquired natural gas collars for 2010 to maintain the Company's strong derivative position, issued senior notes and common stock, pre-paid the Haynesville Shale drilling carry in order to unlock potential capital for PXP's other high-quality assets, and reduced general and administrative costs and lease operating expenses in excess of our stated targets. PXP ended the year with no near-term debt maturities and approximately $990 million available under its senior revolving credit facility.

We believe our balanced portfolio of assets, our 2009 deleveraging transactions and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities. We have a balanced, geographically diverse, lower-risk portfolio of producing properties which underpin our long-term growth strategy; we have financial liquidity; and we have a talented and dedicated workforce. These are the catalysts supporting our Corporate goals to double production and reserves by year-end 2014, remain balanced between oil and gas, and continue reducing total production costs per barrel of oil equivalent. PXP remains diligent on employee training and growth, environmental health and operational safety, financial liquidity, cost control, commodity price and risk management, and reserve and production growth.

The Board of Directors and PXP management want to express our appreciation to each of our shareholders, partners, and employees for their continued confidence and support.

Chairman, President and
Chief Executive Officer


10-K
PXP

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

FORM 10-K

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

For the fiscal year ended December 31, 2009

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 whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 (Do not check if a smaller reporting company) __ 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 $3.3 billion on June 30, 2009 (based on $27.36 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date). On January 29, 2010, there were 139.4 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 2010 Annual Meeting of Stockholders.

PLAINS EXPLORATION & PRODUCTION COMPANY
2009 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, including those related to climate change;
- 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, or SEC. Moreover, although we believe the expectations reflected in the forward-looking statements are based upon reasonable assumptions, we can give no assurance that we will attain these expectations or that any deviations will not be material. We do not intend to update these forward-looking statements and information except as required by law. See Item 1A – "Risk Factors" and Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" 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. 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 directors, principal executive officer, principal financial officer, principal accounting officer and other executive officers) 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 or the SEC's 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:

Analogous reservoir. Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, *analogous reservoir* refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

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.

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

Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

Estimated ultimate recovery. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

Extension well. An extension well is a well drilled to extend the limits of 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.

MMcfe. One million cubic feet of gas equivalent.

MMBOE. One million BOE.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of gas.

NYMEX. New York Mercantile Exchange.

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.

Play. A geographic area with hydrocarbon potential.

Probabilistic Estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrences.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following: (i) the area identified by drilling and limited by fluid contacts, if any; and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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. In our calculation of reserve life, production volumes are based on annualized fourth quarter production and are adjusted, if necessary, to reflect property acquisitions and dispositions.

Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

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 used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category 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 directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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 "analogous reservoir", "deterministic estimate", "developed oil and gas reserves", "development project", "development well", "economically producible", "estimated ultimate recovery", "exploratory well", "probabilistic estimate", "proved oil and gas reserves", "reasonable certainty", "reliable technology", "reserves", "resources" and "undeveloped oil and gas 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 engaged in the activities of acquiring, developing, exploring and producing oil and gas properties primarily in the United States and were formed as a Delaware corporation in 2002. We own oil and gas properties with principal operations in:

- Onshore California;
- Offshore California;
- the Gulf Coast Region;
- the Gulf of Mexico;
- 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 block offshore Vietnam. We believe our balanced portfolio of assets, our 2009 deleveraging transactions and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities, including our significant Haynesville Shale acreage position and our Gulf of Mexico exploration discoveries.

Oil and Gas Reserves

As of December 31, 2009, we had estimated proved reserves of 359.5 million barrels of oil equivalent, of which 60% was comprised of oil and 64% was proved developed. We have a total proved reserve life of approximately 11 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, 2009, and based on the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials, our reserves had a standardized measure of $2.2 billion.

In December 2008, the SEC issued its final rule, Modernization of Oil and Gas Reporting, which is effective for reporting 2009 reserve information. The primary impacts of the SEC's final rule on our reserve estimates include:

- the use of the twelve-month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) of $61.18 per Bbl for oil and $3.87 per MMBtu for natural gas compared to the year-end reference prices (prior to adjustment for location and quality differentials) of $79.36 per Bbl for oil and $5.79 per MMBtu for natural gas;
- certain of our undeveloped locations are not scheduled to be developed within five years, which had the impact of reducing our proved undeveloped reserves by 25 MMBOE; and

- we were able to support with reasonable certainty proved undeveloped reserves for certain horizontal locations in the Haynesville Shale, more than the two parallel offsets from a proved developed well location allowed under the previous guidelines. The impact increased our proved undeveloped reserves by 11 MMBOE.

Under the SEC's final rule, prior period reserves were not restated.

The following table sets forth certain information with respect to our reserves that, for 2009, were based upon reserve reports prepared by the independent petroleum engineers of Netherland, Sewell & Associates, Inc. and Ryder Scott Company L.P., or Ryder Scott. In 2008, our reserves were based upon (1) reserve reports prepared by Netherland, Sewell & Associates, Inc. and Ryder Scott (95% of reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum engineer (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 engineer (1% of reserve volumes). The reserve volumes and values were determined using the methods prescribed by the SEC, which for 2009 require the use of an average price, calculated as the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. For prior years the SEC rules required the use of year-end prices.

	As of December 31,		
	2009	**2008**	**2007**
Oil and Gas Reserves			
Oil (MBbls)			
Proved developed	144,839	123,522	227,915
Proved undeveloped	69,191	54,185	208,618
	214,030	177,707	436,533
Gas (MMcf)			
Proved developed	509,121	515,180	757,736
Proved undeveloped	363,987	171,177	762,240
	873,108	686,357	1,519,976
MBOE	359,548	292,100	689,862
Standardized Measure (in thousands) (1)	$ 2,224,839	$ 1,136,374	$ 7,623,323
Average realized price (2)			
Oil (per Bbl)	$ 54.38	$ 31.75	$ 85.50
Gas (per Mcf)	$ 3.53	$ 5.50	$ 6.28
Reference price (3)			
WTI Oil (per Bbl)	$ 61.18	$ 44.60	$ 95.98
Henry Hub Gas (per MMbtu)	$ 3.87	$ 5.71	$ 7.48
Reserve life (years)	11.2	9.9	18.0

(1) Our year-end 2009 standardized measure includes future development costs related to proved undeveloped reserves of $186 million in both 2010 and 2011 and $225 million in 2012.

(2) Reflects the average realized price in our reserve reports based on the twelve-month average of the first-day-of-the-month reference prices for 2009 and year-end prices for prior years, in each case adjusted for location and quality differentials. The market price for California crude oil differs from the established market indices due primarily to transportation and refining costs of heavy crude.

(3) Reflects the twelve-month average of the first-day-of-the-month reference prices for 2009 and the year-end reference prices for prior years. Our reference prices are the West Texas Intermediate spot price for oil and the Henry Hub spot price for gas.

In 2009, we had a total of 57 MMBOE of extensions and discoveries, including 53 MMBOE in the Haynesville Shale resulting from successful drilling during 2009 that extended and developed the proved acreage and 2 MMBOE of extensions and discoveries in the Gulf of Mexico, primarily attributable to continued success in the Flatrock area. In 2009, we had a total of 2 MMBOE of proved reserves additions related to interests acquired in the Haynesville Shale. In 2009, we had net positive revisions of 39 MMBOE. Positive revisions of 77 MMBOE were primarily related to higher oil prices principally at our California properties. Negative revisions of 13 MMBOE mostly related to lower gas prices, primarily at our Panhandle and South Texas properties. Additionally, certain of our undeveloped locations are scheduled for development beyond five years and were excluded from our proved reserves, resulting in a negative revision of 25 MMBOE.

In 2008, we had extensions and discoveries of 42 MMBOE, including proved reserves from the Haynesville Shale (15 MMBOE) and the Gulf of Mexico (12 MMBOE), primarily attributable to continued success in the Flatrock area. We also acquired 16 MMBOE of reserves primarily related to our South Texas properties. We had a total of 215 MMBOE of negative revisions, 204 MMBOE of which were due to significantly lower 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 2008. We had 207 MMBOE of divestments primarily consisting of all of our Permian Basin, Piceance Basin and San Juan Basin oil and gas properties.

During the three-year period ended December 31, 2009, we participated in 275 exploratory wells, of which 252 were successful, including 191 successful Haynesville Shale wells, and 506 development wells, of which 501 were successful. During this period, we incurred aggregate oil and gas acquisition, exploration and development costs of $12.5 billion, approximately 82% of which was for acquisition and development activities. During this period, proved reserve additions from acquisitions, extensions and discoveries totaled 386 MMBOE.

Approximately 2% of our proved undeveloped reserves are scheduled for development beyond five years and approximately 7%, or $88 million, of our future estimated capital to develop proved undeveloped reserves is associated with those reserves. Undeveloped reserves scheduled for development beyond five years reflect additional time necessary to optimize wellbore utilization in two offshore Gulf of Mexico fields. We expect to first deplete the current completed zones before we can sidetrack for other undeveloped reserves, which are primarily gas.

As of December 31, 2009, we had proved undeveloped reserves of 130 MMBOE, an increase of 47 MMBOE relative to December 31, 2008. Significant additions to proved undeveloped reserves resulted primarily from continued successful development of the Haynesville Shale as well as positive revisions for our Onshore California locations due to higher 2009 average oil prices, offset by downward revisions in our Panhandle and South Texas properties due to significantly lower 2009 average gas prices. Additionally, we have a number of undeveloped locations scheduled for development beyond five years that further reduced our proved undeveloped reserves by 25 MMBOE. During 2009, we invested $48 million and converted 3 MMBOE, or 4% of our year-end 2008 proved undeveloped reserve balance, to proved developed. This pace of development was heavily influenced by the low commodity price and high service cost environment that was prevalent for a significant portion of 2009.

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 by 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.

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 the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials for December 31, 2009 reserves and year-end prices for prior periods, 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. The reserve estimates exclude the effect of any derivative instruments 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.

Internal Control

Our corporate reservoir engineering department reports to the Vice President of Engineering who maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to independent third party engineers for the annual estimation of our year-end reserves. The management of our corporate reservoir engineering group, including the Vice President of Engineering, consists of three degreed petroleum engineers, with between 20 and 33 years of industry experience, between 10 and 33 years of reservoir engineering/management experience, and between 4 and 8 years of experience managing our reserves. All are members of the Society of Petroleum Engineers.

Qualifications of Third Party Engineers

The technical personnel responsible for preparing the reserve estimates at both Netherland, Sewell & Associates, Inc. and Ryder Scott meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Both Netherland, Sewell & Associates, Inc. and Ryder Scott are independent firms of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

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, or 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, which we refer to as the Haynesville Carry. 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. At the acquisition date there were no material proved reserves associated with the leasehold interests acquired.

In August 2009, we amended the participation agreement with Chesapeake to accelerate the payment of the remaining Haynesville Carry. On September 29, 2009, we paid $1.1 billion to Chesapeake for the remaining Haynesville Carry balance as of September 30, 2009, which we estimated to be $1.25 billion, an approximate 12% reduction. We funded the payment with net proceeds from the sale of our common stock and the issuance of $400 million of $8^{5}/_{8}$% Senior Notes due 2019, cash on hand and borrowings from our senior revolving credit facility. Chesapeake committed to drill at least 150 wells per year under the participation agreement for the three-year period beginning October 1, 2009. Additionally, we agreed to terminate our one-time option exercisable in June 2010, which would have relieved us of our obligation to pay the last $800 million of the Haynesville Carry in exchange for an assignment to Chesapeake of 50% of our interest in our Haynesville acreage. As a result of the prepayment of the Haynesville Carry, we will not pay promoted well costs for costs attributable to periods subsequent to the third quarter of 2009. During 2009, we spent $59 million to acquire approximately 5,000 net additional acres in the Haynesville Shale, and at December 31, 2009 we had approximately 111,000 net acres in the Haynesville Shale, including approximately 61,000 net acres of leasehold that we believe is also prospective for the Bossier Shale.

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 Producing Company, or 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. The acquisition, which was effective November 6, 2007, was accounted for under the purchase method of accounting.

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 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, or CVGG. We sold these properties in 2008. See "Divestments".

Divestments

In February 2008, we closed the sale of certain oil and gas properties to a subsidiary of Occidental Petroleum Corporation, or 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 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 "Acquisitions".

In February 2008, we closed the sale to XTO Energy Inc., or 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.

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 $1.23 billion in cash proceeds, after closing adjustments. We sold the remaining 50% of our working interests in oil and gas properties located in the Permian and Piceance Basins, including a 50% interest in the entity that held our interest in CVGG. 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.

Development and Exploration

We expect to continue growing reserves and production through the long-term development of our existing project inventory in each of our primary operating areas and by building future development projects through exploration primarily in the Gulf Coast Region, Gulf of Mexico 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, 2009, our additions to proved reserves from extensions and discoveries totaled 130 MMBOE. During this period we incurred aggregate oil and gas development and exploration costs of $3.5 billion.

Our 2010 capital budget is approximately $1.2 billion and is focused on our major development and exploration areas. Our resources will be primarily directed to the Haynesville Shale, continued development activities in California, South Texas and the Panhandle and our exploration and development projects in the Gulf Coast and Gulf of Mexico. 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 Coast Region, the Gulf of Mexico, the Mid-Continent Region and the Rocky Mountains. We also have an interest in an exploration block 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.

Our capital investments are allocated to asset areas with the greatest expected returns and highest growth prospects. These investments support a diversified growth strategy with sustained development of our base properties in the Gulf Coast Region, the Gulf of Mexico, California and our Texas asset areas, as well as continued exploration primarily in the onshore Gulf Coast Region and Gulf of Mexico. Capital additions to our oil and gas properties, excluding acquisitions, were $1.6 billion in 2009.

The following table sets forth information with respect to our proved oil and gas reserves as of December 31, 2009:

	Proved Reserves as of December 31, 2009 (1)		
	Proved Developed	Proved Undeveloped	Total Proved
		(MMBOE)	
Onshore California	134.2	69.6	203.8
Offshore California	11.6	-	11.6
Gulf Coast Region	32.6	48.0	80.6
Gulf of Mexico	9.8	2.8	12.6
Mid-Continent Region	13.8	9.4	23.2
Rocky Mountains	27.7	-	27.7
Total	229.7	129.8	359.5

(1) In December 2008, the SEC issued its final rule, Modernization of Oil and Gas Reporting, which is effective for reporting 2009 reserve information. See "Oil and Gas Reserves".

Onshore California

Los Angeles Basin

We hold a 100% working interest in the majority of our Los Angeles Basin, or 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 2009, we spent $24 million on capital projects in the LA Basin, focused on producer and injector well recompletions to improve waterflood recovery efficiency and facility additions and enhancements to process higher fluid volumes. Our net average daily LA Basin sales volumes were 11.8 MBOE per day in the fourth quarter of 2009. In 2010, we plan to concentrate on development drilling and on recompletion projects in the LA Basin.

San Joaquin Basin

Our San Joaquin Basin properties are located 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 $33 million in 2009 on capital projects in the San Joaquin Basin focused on well recompletions, facility expansions and enhancements to reduce air emissions, primarily at the Cymric and Midway Sunset Fields and drilled five wells at the Cymric Field. Our net average daily San Joaquin Basin sales volumes were 18.5 MBOE per day in the fourth quarter of 2009.

We are evaluating our exposure to the recently announced positive industry discovery in Kern County, California. We hold approximately 12,800 net acres in the Kern County area. In 2010, we plan to concentrate on development drilling and on recompletion projects and facility expansions in the San Joaquin Basin. Additionally, we are developing a diatomite expansion project in a new area.

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) and well depths averaging 1,700 feet and requires continuous steam injection. In 2009, we spent $4 million on capital projects in this field and drilled 7 wells, including 2 injection wells. Our net average daily sales volumes from the Arroyo Grande Field were 1.2 MBOE per day in the fourth quarter of 2009.

We have obtained permits to construct a water reclamation and treatment facility to improve operating efficiencies for oil recovery activities. The new facility is designed to accelerate field development and production growth. We expect to begin construction on the facility in 2011.

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. Our net average daily sales volumes in the fourth quarter of 2009 were 3.7 MBOE per day. Much of our planned activity on this property in 2010 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 2009, we spent $30 million on capital projects primarily associated with capacity expansion, equipment improvements and one sidetracked well. Our combined net average daily sales volumes from our Pt. Pedernales and Lompoc Fields averaged 6.4 MBOE per day in the fourth quarter of 2009. During 2010, we plan to drill an additional extended reach Monterey well in this area. In addition, we are pursuing leases for the Tranquillon Ridge Field located in state waters adjacent to the Point Pedernales Field, which can be drilled from our existing federal platform. Such leases require regulatory action, which approval cannot be guaranteed.

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

Haynesville Shale

In July 2008, we acquired from Chesapeake a 20% interest in Chesapeake's Haynesville Shale leasehold. See "Acquisitions". 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. As of December 31, 2009, we have rights to approximately 683,000 gross acres (111,000 net), including approximately 61,000 net acres of leasehold that we believe is also prospective for the Bossier Shale. Based on the potential of 80 acre well spacing, we anticipate that there could be over 8,500 potential drilling locations after applying a risk weighting.

Drilling operations began in July 2008 and production commenced during the third quarter of 2008. Our net average daily sales volumes during the fourth quarter of 2009 were 75 MMcfe per day, a 436% increase from the 14 MMcfe per day net average during the first quarter of 2009. Production is expected to continue to increase to approximately 125 MMcfe net per day by year-end 2010. During 2010, Chesapeake is expected to operate an average of approximately 40 rigs and other operators are expected to operate 15 or more rigs on our acreage.

We spent $652 million of capital in 2009, including $375 million of promoted well costs, drilling 316 wells, of which 149 were drilling or awaiting completion at December 31, 2009. For 2010, we allocated $300 million of our capital budget to Haynesville activity. As a result of the prepayment of the Haynesville Carry, we will not pay promoted well costs for costs attributable to periods subsequent to the third quarter of 2009.

South Texas

We own interests in oil and gas properties on approximately 90,360 gross acres (55,705 net acres) with 321 square miles of 3-D seismic located in South Texas, including approximately 52,648 gross acres (29,453 net acres) that we acquired in April 2008 from a private company.

Our South Texas development activities are primarily focused on gas reserves concentrated in the Los Mogotes, Lopez Ranch, Mills Bennett and Javelina Fields. The fields produce from the Eocene Yegua and Wilcox formations, found at depths generally ranging from 7,000 to 14,000 feet.

During 2009, we spent $25 million on exploration and development projects in this area primarily associated with drilling activities and we drilled eight wells, one of which was in progress at year-end. Our net average daily sales volumes from these properties were 8.9 MBOE per day for the fourth quarter 2009. In 2010, we plan to continue focusing on development in these fields.

East Texas

We hold approximately 51,160 gross acres, including the Cretaceous Woodbine and Austin Chalk Formations in Polk and Tyler Counties. We own approximately 128 square miles of proprietary 3-D seismic data.

Gulf of Mexico

We have both 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. Our Gulf of Mexico exploration program is dynamic and is a cornerstone to our strategy of building future development projects. We spent $533 million in 2009 on exploration and development projects in our Gulf of Mexico asset areas and participated in 14 wells. One was successful and put on production in 2009. Seven of these wells were classified as in progress at year end, five of which were deemed successful either in 2009 or early 2010. These five wells include the previously announced Lucius, Blueberry Hill, and Davy Jones discoveries. Six of the 14 wells were unsuccessful.

McMoRan Drilling Program

We have an exploration agreement with McMoRan Exploration Co., or McMoRan, to participate in several of their Miocene exploratory prospects.

- Our Flatrock development has been very successful, contributing meaningful sales volume growth. Production commenced at Flatrock, where we own a 30% working interest, in the first quarter of 2008. As of December 31, 2009, we have drilled a total of six wells and production averaged 58 MMCFE per day in the fourth quarter of 2009. In May 2009, the operator completed a planned facility expansion at the Tiger Shoal production facility.

- As of December 31, 2009, a well drilled at Blackbeard West on South Timbalier Block 168, where we own a 35% working interest, awaits completion. We plan to drill a second well on the East side of this prospect during 2010.

- Positive drilling results at the Blueberry Hill deep gas exploratory well, operated by McMoRan and located on Louisiana State Lease 340 in the Gulf of Mexico, indicate a discovery. The exploratory sidetrack well was drilled to a true vertical depth of 21,942 feet and encountered 45 net feet of pay in October 2009. The offset appraisal well commenced drilling in November 2009. We hold a 47.9% working interest.

- Positive drilling results at the Davy Jones ultra-deep prospect operated by McMoRan indicate a discovery. Flow testing will be required to confirm the ultimate hydrocarbon flow rates from the well. An appraisal well to the southwest of the initial Davy Jones well is planned for 2010. We have a 28% working interest.

Onshore and Offshore Areas of Texas and Louisiana

Jefferson County, Texas. We hold a 100% working interest in approximately 33,400 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. During 2010 we plan to drill two prospects in this area.

South Louisiana. We hold approximately 34,200 gross acres in central South Louisiana on which to explore Oligocene, deeper Eocene and Paleocene targets. We own over 165 square miles of new 3-D seismic data in central South Louisiana and hold a 100% working interest.

Deepwater Gulf of Mexico

In the deepwater area of the Gulf of Mexico, we participated in five exploration wells in 2009, including the Lucius discovery in Keathley Canyon Block 875 and three unsuccessful wells, which were drilled in Garden Banks Block 988, Keathley Canyon Block 470 and Green Canyon Block 945.

In December 2009, the Lucius discovery was drilled to a total depth of about 20,000 feet in approximately 7,100 feet of water and encountered more than 200 feet of net pay in subsalt Pliocene and Miocene Sands. In January 2010, the Lucius sidetrack appraisal well encountered almost 600 feet of high-quality net oil pay with additional gas-condensate pay in thick subsalt Pliocene and Miocene sands. The Lucius appraisal well was drilled as an up-dip sidetrack, approximately 3,200 feet due south of the discovery well. It was drilled to a total depth of approximately 20,600 feet in approximately 7,100 feet of water. Additional appraisal activity is planned to evaluate development options. We have a 33.3% working interest.

We have a 100% working interest in the Friesian discovery well announced in November 2006. During 2009, the Friesian #2 well, operated by us and located in Green Canyon 643, was drilled to a total depth of approximately 33,900 feet and encountered approximately 500 net feet of oil pay in the M-13 through M-18 sands. Well results are being evaluated and early stage commercialization initiatives for Friesian production are under study.

During 2010, our plans in the deepwater Gulf of Mexico include further work on the commercialization initiatives for Friesian and additional geologic and geophysical studies. We also plan to drill two wells, which Anadarko will operate.

Mid-Continent Region

We have interests in oil and gas properties on approximately 405,700 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 areas in Wheeler and Hemphill Counties in Texas. The structural and stratigraphic objectives include Cleveland Sands, Mississippian carbonates, Granite Wash 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 $30 million on exploration and development projects in 2009, including development drilling in the Wheeler and Marvin Lake areas as well as exploration drilling at the Courson and Turkey Track Ranches. Our net average daily sales volumes from our Mid-Continent Region properties were 5.9 MBOE per day in the fourth quarter of 2009.

We are currently evaluating our exposure to the recently announced positive industry Granite Wash results in the Texas Panhandle. We hold leases covering 9,040 gross and about 5,650 net acres in the Stiles Ranch Field area in Wheeler County, Texas. The acreage is located within the productive trend of horizontal drilling that is targeting multiple Pennsylvanian Granite Wash and Atoka Wash reservoirs. In addition to the horizontal potential at Wheeler, we are also evaluating the horizontal potential of the Marvin Lake Area in Hemphill County, Texas, where we hold approximately 12,000 gross and net acres. We have identified a minimum of 58 horizontal well locations targeting discrete units within the Granite Wash and Atoka Wash section. More information is being obtained and added to the interpretation both regionally and locally. It is likely that more locations will be identified as additional information is integrated and the critical criteria for economically attractive horizontal targets are better defined.

In 2010, we plan to concentrate our development drilling in the Wheeler and Marvin Lake areas focusing on horizontal Granite Wash development, as well as additional exploration.

Rocky Mountains

Wind River Basin

We own a 14% working interest in the Madden Deep Unit and Lost Cabin Gas Plant located in central Wyoming. The Madden Deep Unit is a federal unit operated by a third party and consists of approximately 63,840 gross acres in the Wind River Basin. The Madden Deep 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 Deep Unit is typically found at depths ranging from 5,500 to 25,000 feet. Some of the gas produced from the Madden Deep Unit requires processing at the Lost Cabin Gas Plant to remove high concentrations of carbon dioxide and hydrogen sulfide.

In 2009, we spent $3 million on capital projects in the Madden Deep Unit. Our net average daily sales volumes were 5.0 MBOE per day for the fourth quarter of 2009.

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 the drilling of two exploratory wells, which were plugged and abandoned after encountering a minor structurally controlled hydrocarbon accumulation in one well. In the fourth quarter of 2009, we obtained 520 kilometers of 2-D seismic data and the government of Vietnam granted a one-year extension of the first phase of our production sharing contract. We continue to evaluate our plans for future operations in Block 124 utilizing the 3-D seismic data, the data from the two exploratory wells and the 2-D seismic data, and we expect to finalize our plans during 2010.

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,		
	2009	2008	2007
	(In thousands of dollars)		
Property acquisition costs:			
Unproved properties	$ 1,121,644	$ 1,878,842	$ 1,822,312
Proved properties	5,072	267,161	3,883,607
Exploration costs	1,309,396	520,612	465,246
Development costs	272,820	576,753	357,345
	$ 2,708,932	$ 3,243,368	$ 6,528,510

Production and Sales

The following table presents information with respect to oil and gas production attributable to our properties, average sales prices we realized and our average production expenses during the years ended December 31, 2009, 2008 and 2007.

	Inglewood [1]	Haynesville Shale [1]	Other	Total
2009				
Oil and liquid sales (MBbls)	2,407	-	15,153	17,560
Gas (MMcf)				
Production	1,013	15,176	61,995	78,184
Used as fuel	21	-	2,337	2,358
Sales	992	15,176	59,658	75,826
BOE				
Production	2,576	2,529	25,486	30,591
Sales	2,572	2,529	25,097	30,198
Average realized sales price before derivative transactions [2]				
Oil (per Bbl)	$ 51.91	$ -	$ 51.36	$ 51.43
Gas (per Mcf)	3.72	3.50	3.77	3.72
Per BOE	50.01	21.01	39.98	39.25
Average production cost per BOE [3]				
Lease operating expenses	$ 14.20	$ 0.96	$ 8.44	$ 8.31
Steam gas costs	-	-	2.14	1.78
Electricity	6.38	-	1.10	1.45
Gathering and transportation	0.11	4.70	0.98	1.21
2008				
Oil and liquid sales (MBbls)	2,589	-	17,705	20,294
Gas (MMcf)				
Production	980	556	77,718	79,254
Used as fuel	-	-	2,223	2,223
Sales	980	556	75,495	77,031
BOE				
Production	2,752	93	30,658	33,503
Sales	2,752	93	30,288	33,133
Average realized sales price before derivative transactions [2]				
Oil (per Bbl)	$ 93.09	$ -	$ 86.17	$ 87.05
Gas (per Mcf)	7.76	5.68	8.07	8.05
Per BOE	90.34	34.08	70.48	72.03
Average production cost per BOE [3]				
Lease operating expenses	$ 16.34	$ 0.96	$ 9.32	$ 9.88
Steam gas costs	-	-	4.33	3.96
Electricity	8.22	-	0.99	1.59
Gathering and transportation	0.06	4.15	0.68	0.64

Table continued on following page.

	Inglewood (1)	Other	Total
2007			
Oil and liquid sales (MBbls)	2,718	15,406	18,124
Gas (MMcf)			
Production	1,160	28,152	29,312
Used as fuel	-	2,302	2,302
Sales	1,160	25,850	27,010
BOE			
Production	2,912	20,098	23,010
Sales	2,912	19,713	22,625
Average realized sales price before derivative transactions (2)			
Oil (per Bbl)	$ 65.29	$ 60.94	$ 61.60
Gas (per Mcf)	6.39	5.65	5.68
Per BOE	63.50	55.03	56.12
Average production cost per BOE (3)			
Lease operating expenses	$ 11.65	$ 9.73	$ 9.98
Steam gas costs	-	5.25	4.57
Electricity	6.44	1.07	1.76
Gathering and transportation	0.04	0.57	0.50

(1) The field has been attributed total proved reserves greater than 15% of our total proved reserves. The Inglewood field is located onshore California and the Haynesville Shale is located onshore Louisiana and Texas.

(2) 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. Our derivative transactions are not included in oil and gas sales because they are not classified as hedges for accounting purposes.

(3) Does not include production and ad valorem taxes.

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 and gas price collar contracts entered into with financial institutions.

A substantial portion of our oil reserves are located in California and approximately 55% 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 fifteen-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 2009. During 2009, we received approximately 88% of the NYMEX index price for crude oil sold under the ConocoPhillips contract, which represented approximately 47% of our total crude oil production.

Approximately 24% of our 2009 crude oil production is sold under contracts that provide for NYMEX less a fixed price differential (as of December 31, 2009 averaging the fixed price differential of $7.04 per barrel) with the remainder sold under contracts that provide for monthly field posted prices.

Our share of production from the Haynesville Shale is sold by Chesapeake under the terms of a fifteen-year contract with a primary term which expires on September 1, 2023. The contract with Chesapeake provides that Chesapeake will sell our production along with its own for which Chesapeake charges a marketing fee.

Prices received for our gas are subject to seasonal variations and other fluctuations. Approximately 48% 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 spot and index prices can significantly impact the overall differential to the Henry Hub.

During 2009, 2008 and 2007, sales to ConocoPhillips accounted for 44%, 36% and 45%, respectively, of our total revenues and sales to Plains Marketing, L.P., or PMLP, accounted for 22%, 23% and 31%, respectively, of our total revenues. During such periods no other purchaser accounted for more than 10% of our total revenues. As expected, the contract with PMLP expired in November 2009, and we have entered into contracts with purchasers who have previously purchased through PMLP. One of those purchasers was ConocoPhillips, and as such, we anticipate that sales to ConocoPhillips could account for approximately 60% of our total revenues in 2010, based on our current production figures. 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, significant purchasers of our oil and gas production can potentially impact our overall exposure to credit risk.

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, 2009, we had working interests in 2,866 gross (2,765 net) active producing oil wells and 1,515 gross (798 net) active producing gas wells. The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2009:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Domestic (1)				
California				
Onshore	59,572	58,353	43,972	28,982
Offshore	43,335	39,062	-	-
Louisiana				
Onshore	105,309	22,871	481,323	119,043
Offshore	48,082	23,859	519,956	141,024
Oklahoma	19,749	6,118	11,671	8,443
Texas	305,594	170,063	473,129	267,345
Utah	-	-	66,591	32,293
Wyoming	65,151	8,033	134,070	114,346
Other states (2)	11,773	8,022	28,338	15,694
	658,565	336,381	1,759,050	727,170
Vietnam (3)	-	-	1,480,000	1,480,000
	658,565	336,381	3,239,050	2,207,170

(1) Approximately 44% of our domestic total net undeveloped acres is covered by leases that expire from 2010 through 2012. 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 and North Dakota.
(3) Pursuant to our contract with PetroVietnam, we will be required to designate 20% of this acreage for relinquishment during 2010.

Drilling Activities

Information with regard to our drilling activities during the years ended December 31, 2009, 2008 and 2007 is set forth below:

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells (1)						
Oil	1.0	1.0	7.0	2.7	-	-
Gas	156.0	19.6	52.0	18.1	36.0	32.1
Dry	10.0	6.6	5.0	3.6	8.0	4.9
	167.0	27.2	64.0	24.4	44.0	37.0
Development Wells						
Oil	16.0	12.7	125.0	90.2	140.0	139.1
Gas	24.0	12.4	159.0	80.0	37.0	35.0
Dry	1.0	0.2	1.0	1.0	3.0	3.0
	41.0	25.3	285.0	171.2	180.0	177.1
	208.0	52.5	349.0	195.6	224.0	214.1

(1) Includes extension wells.

At December 31, 2009, there were 151 gross exploratory and 9 gross development wells (22.7 net exploratory and 1.9 net development wells) in progress.

Real Estate

During 2009, 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

We have 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 2009, we spent approximately $10.5 million on our real estate projects.

Title to Properties

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

We believe that we generally have 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 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 U.S. Environmental Protection Agency, or EPA, 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 Item 1A – "Risk Factors—We are subject to certain regulations, some of which require permits and other approvals. These regulations could increase our costs and may terminate, delay 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, or Nuevo, 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 us.

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 minimis 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, and analogous state laws. 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, and often their state and local counterparts. 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 removal and/or 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. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or the Waxman-Markey Bill. The U.S. Senate is considering a number of comparable measures. One such measure, the Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been reported out of the Senate Committee on Energy and Natural Resources, but has not yet been considered by the full Senate. Although these bills include several differences that would require reconciliation before becoming law, both contain the basic feature of establishing a "cap and trade" system for restricting greenhouse gas emissions in the U.S. Under such a system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require us to incur increased operating costs, and could have an adverse affect on demand for the oil and natural gas we produce. In addition, at least 20 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. In California, for example, the California Global Warming Solutions Act of 2006 (Assembly Bill 32) requires the California Air Resources Board to establish and adopt regulations by 2012 that will achieve an overall reduction in greenhouse gas emissions from all sources in California of 25% by 2020.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of crude oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated oil and gas companies, a stringent greenhouse gas control program could significantly increase our cost of doing business and could also reduce demand for the oil and natural gas we produce.

In April 2007, the United States Supreme Court found that the EPA has the authority to regulate carbon dioxide, or CO_2, emissions from automobiles as "air pollutants" under the Clean Air Act, or the

CAA. On December 7, 2009, the EPA issued its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act," which became effective in January 2010. In this finding, the EPA concluded that the atmospheric concentrations of several key greenhouse gases threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key greenhouse gases and hence to the threat of climate change. This finding provides the regulatory underpinning for future greenhouse gas regulations. Effective December 29, 2009, the EPA also adopted a greenhouse gas reporting rule establishing a national greenhouse gas emissions collection and reporting program. The EPA rules will require covered entities to measure greenhouse gas emissions commencing in 2010 and submit reports commencing in 2011. The EPA also proposed in September 2009 new thresholds for greenhouse gas emissions that define when certain permits would be required. The EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the greenhouse gas significance level. These proposals, along with new federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business and demand for the crude oil and natural gas we produce.

The U.S. Senate and House of Representatives are currently considering bills, entitled "Fracturing Responsibility and Awareness of Chemicals Act," or FRAC Act, to amend the federal Safe Drinking Water Act, or the SDWA, to repeal an exemption from regulation for hydraulic fracturing. Among other things, the FRAC Act proposes to amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations (which we and our competitors use in our shale gas operations) to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Although the legislation is still being developed, if it were enacted it could have an adverse effect on our operations. In other locations, various state and local agencies (and the EPA) have subjected hydraulic fracturing to increased regulatory scrutiny, although this has not yet affected any of our operations.

As with our industry generally, our compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, upgrade and close equipment and facilities. Although these 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 becoming more 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

For discussion of our obligations to incur plugging, abandonment and remediation costs, see Item 7 – “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Commitments and Contingencies”.

Employees

As of January 31, 2010, we had 808 full-time employees, three of whom were employed in our international operations and 330 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. Any substantial or extended decline in the price of oil and gas below current levels will have a negative impact on our business operations and future revenues. Moreover, oil and gas prices depend on factors we cannot control, such as:

- supply and demand for oil and gas and expectations regarding supply and demand;
- weather;
- actions by OPEC and other major producing companies;
- political conditions in other oil-producing and gas-producing countries, including the possibility of insurgency, terrorism 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 may be impaired in the future periods if oil and gas prices decline.

Under the SEC's full cost accounting rules, we review the carrying value of our oil and gas properties each quarter. Under these rules, for each cost center, 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 cost of unproved properties not being amortized; plus
- the lower of cost or estimated fair value of unproved properties included in the costs being amortized (net of related tax effects).

These rules were modified and generally require that we price our future oil and gas production at the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials and require an impairment if our capitalized costs exceed this "ceiling". Due to significantly depressed oil prices during the first quarter of 2009 and declining gas prices throughout the year, the twelve-month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) were $61.18 per Bbl for oil and $3.87 per MMBtu for natural gas compared to the year-end reference prices (prior to adjustment for location and quality differentials) of $79.36 per Bbl for oil and $5.79 per MMBtu for natural gas. At December 31, 2009, the ceiling with respect to our oil and gas properties exceeded the net capitalized costs by an insignificant amount and we did not record an impairment. Had the calculation been made using the year-end prices, the excess would have been higher.

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. We may be required to recognize non-cash pre-tax impairment charges in future reporting periods if market prices for oil or natural gas decline.

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

The proved oil and gas reserve information included in this document represents only estimates. These estimates are based on reports prepared by independent petroleum engineers and us. The estimates were calculated using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials for the December 31, 2009 reserves compared to the year-end prices for prior years. 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 costs as of the date of the estimates and the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials for 2009 and the year-end prices for prior years. 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 lower oil and natural gas prices. Lower oil and natural gas prices not only decrease our revenues, 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 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, on average, 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 oil and gas production, which exposes us to the risk of financial loss and may result in us 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 for a portion of our oil and gas production. 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;
- 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.

See Item 7A – "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our current derivative positions. Since all of our derivative contracts are accounted for using mark-to-market accounting, we expect continued volatility in derivative gains or losses on our income statement as changes occur in the NYMEX price indices.

Potential regulations regarding derivatives could adversely impact our ability to engage in commodity price risk management activities.

We use derivative instruments to manage our commodity price risk. The U.S. Congress is considering measures aimed at increasing the transparency and stability of the over-the-counter, or OTC, derivative markets and preventing excessive speculation. Proposals being considered would impose clearing and standardization requirements for OTC derivatives and restrict trading positions in the energy futures markets. It is not possible at this time to predict whether or when Congress may act on derivatives legislation. However, any laws or regulations that may be adopted that subject us or our hedging counterparties to additional capital or margin requirements or to additional restrictions on trading and commodity positions could materially reduce our hedging opportunities and increase the costs associated with our hedging programs, both of which would negatively affect our revenues and cash flow.

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.

We engage in exploration and development activities in deep shelf prospects in the shallow waters of the Gulf of Mexico. This area has had limited historical drilling activity and presents unique challenges to production activities not typical of other shallow water Gulf of Mexico prospects including increased risks of mechanical failure due to higher temperatures and pressures encountered at deep depths. As a result, our deep shelf exploration and development activities may not be commercially successful, or could involve significant delays between time of discovery and marketing of production.

In addition, we are currently conducting some of our exploration in the deeper waters of the Gulf of Mexico, where operations are more difficult and costly than in shallower waters. The deeper waters in the Gulf of Mexico lack the physical and oilfield service infrastructure present in its shallower waters. As a result, deepwater operations may require a significant amount of time between a discovery and the time that we can market our production, thereby increasing the risk involved with these operations.

The majority of our oil production is dedicated to one customer and as a result, our credit exposure to this customer is significant.

We have entered into an oil marketing arrangement with ConocoPhillips under which ConocoPhillips purchases the majority of our net oil production. We generally do not require letters of credit or other collateral to support these trade receivables. Accordingly, a material adverse change in their 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.

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

While there are signs that the economy may be improving, the potential remains for further volatility and disruption in the capital and credit markets. During 2009, 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 return, 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. The commitments are from a diverse syndicate of 22 lenders. At December 31, 2009, no single lender's commitment represented more than 7% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

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.

We are subject to certain regulations, some of which require permits and other approvals. These regulations could increase our costs and may terminate, delay 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. Certain of these regulations require permits for the drilling and operation of wells. 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.

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.

In addition, our real estate entitlement efforts are subject to regulatory approvals. Some of these regulatory approvals 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 procedures 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, prevented or made more expensive.

Possible regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to the warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are examples of greenhouse gases. The U.S. Congress is considering climate-related legislation to reduce emissions of greenhouse gases. In addition, at least 20 states have developed measures to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. The EPA has adopted regulations requiring reporting of greenhouse gas emissions from certain facilities and is considering additional regulation of greenhouse gases as "air pollutants" under the existing federal Clean Air Act. Passage of climate change legislation or other regulatory initiatives by Congress or various states, or the adoption of regulations by the EPA or analogous state agencies, that regulate or restrict emissions of greenhouse gases (including methane or carbon dioxide) in areas in which we conduct business could have an adverse effect our operations and the demand for oil and natural gas.

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 historical 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 100 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 187 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.

Proposed federal legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Legislation has been proposed in the U.S. Congress to amend the Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formation to stimulate natural gas production. The use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs, especially shale formations such as the Haynesville Shale. If adopted, this legislation could establish an additional level of regulation and permitting at the federal level. This additional regulation and permitting could result in additional burdens such as operational delays or increased operating costs and make it more difficult to perform hydraulic fracturing.

Certain of our undeveloped leasehold acreage are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2009, we had leases on approximately 111,000 net acres in the Haynesville Shale area. A sizeable portion of this acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Further, since we do not operate the acreage, we have limited impact upon the drilling schedule for these leases.

Increased drilling in the Haynesville Shale may cause pipeline and gathering system capacity constraints that could limit our ability to sell our oil and gas.

If our drilling in the Haynesville Shale continues to be successful, the amount of gas being produced in the area from our new wells, as well as gas produced from other wells, may exceed the capacity of gathering and intrastate and interstate transportation pipelines. If this occurs, it will be necessary for new interstate and intrastate pipelines and gathering systems to be built.

Because of the current economic climate, certain pipeline projects that are planned for the Haynesville Shale area may not occur because the prospective owners of these pipelines may be unable to secure the necessary financing. In such event, this could result in wells being shut-in awaiting a pipeline connection or capacity and/or gas being sold at much lower prices than those quoted on the NYMEX or than we currently project, which would adversely affect our results of operations.

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 assessing recoverable reserves, exploration potential, future production rates, operating costs, infrastructure requirements, future oil and natural gas prices, 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.

Assessments associated with an acquisition are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every oil and gas well or the facilities associated with those wells. Even when we perform inspections, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and gas properties may exceed the value we realize.

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 are prohibited to us by such laws.

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, 2009, goodwill totaled $535 million and represented approximately 7% 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 Estimates—Goodwill".

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 oil and natural gas 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.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in President Obama's Fiscal Year 2011 budget proposal, released by the White House on February 1, 2010, is the elimination or deferral of certain key U.S. federal income tax deductions currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Additionally, the Senate bill version of the Oil Industry Tax Break Repeal Act of 2009, introduced on April 23, 2009, the Senate bill version of the Energy Fairness for America Act, introduced on May 20, 2009 and President Obama's Fiscal Year 2010 budget proposal, released on February 26, 2009 include many of the proposals outlined in President Obama's Fiscal Year 2011 budget proposal. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation as a result of the budget proposal, either Senate bill or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial results.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 3. *Legal Proceedings*

We are a defendant in various 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
2009		
1st Quarter	$ 27.20	$ 15.25
2nd Quarter	32.87	16.40
3rd Quarter	32.29	23.49
4th Quarter	31.60	24.40
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

At January 29, 2010, we had approximately 2,508 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 has the authority to declare and pay dividends on our common stock at their 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", our credit facility and indentures restrict our ability to pay cash dividends.

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, 2009 and 2008 and the related consolidated statements of income and cash flows for each of the three years in the period ended December 31, 2009 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,				
	2009	2008 [1]	2007 [2]	2006	2005
	(In thousands, except per share amounts)				
Revenues	$ 1,187,130	$ 2,403,471	$ 1,272,840	$ 1,018,503	$ 944,420
Costs and Expenses					
Production costs	423,967	626,428	413,122	313,125	285,292
General and administrative	144,586	153,306	124,006	123,134	127,513
Depreciation, depletion, amortization and accretion	421,580	621,484	316,078	216,782	187,915
Impairment of oil and gas properties [3]	-	3,629,666	-	-	-
Gain on sale of oil and gas properties [4]	-	-	-	(982,988)	-
Legal recovery	(87,272)	-	-	-	-
Other operating expenses	2,136	-	-	-	-
	904,997	5,030,884	853,206	(329,947)	600,720
Income (Loss) from Operations	282,133	(2,627,413)	419,634	1,348,450	343,700
Other Income (Expense)					
Gain on sale of assets [5]	-	65,689	-	-	-
Interest expense	(73,811)	(116,991)	(68,908)	(64,675)	(55,421)
Debt extinguishment costs	(12,093)	(18,256)	-	(45,063)	-
(Loss) gain on mark-to-market derivative contracts [6]	(7,017)	1,555,917	(88,549)	(297,503)	(636,473)
Gain on termination of merger agreement [7]	-	-	-	37,902	-
Other income (expense)	27,968	(12,575)	6,322	5,496	3,324
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	217,180	(1,153,629)	268,499	984,607	(344,870)
Income tax (expense) benefit					
Current	(45,091)	(230,815)	4,677	(142,378)	229
Deferred	(35,784)	675,350	(114,425)	(242,519)	130,629
Income (Loss) Before Cumulative Effect of Accounting Change	136,305	(709,094)	158,751	599,710	(214,012)
Cumulative effect of accounting change, net of tax expense [8]	-	-	-	(2,182)	-
Net Income (Loss)	$ 136,305	$ (709,094)	$ 158,751	$ 597,528	$ (214,012)
Earnings (Loss) Per Share					
Basic					
Income (loss) before cumulative effect of accounting change	$ 1.10	$ (6.52)	$ 2.02	$ 7.76	$ (2.75)
Cumulative effect of accounting change	-	-	-	(0.03)	-
Net income (loss)	$ 1.10	$ (6.52)	$ 2.02	$ 7.73	$ (2.75)
Diluted					
Income (loss) before cumulative effect of accounting change	$ 1.09	$ (6.52)	$ 1.99	$ 7.67	$ (2.75)
Cumulative effect of accounting change	-	-	-	(0.03)	-
Net income (loss)	$ 1.09	$ (6.52)	$ 1.99	$ 7.64	$ (2.75)
Weighted Average Common Shares Outstanding					
Basic	124,405	108,828	78,627	77,273	77,726
Diluted	125,288	108,828	79,808	78,234	77,726

Table continued on following page.

	Year Ended December 31,				
	2009	2008 (1)	2007 (2)	2006	2005
	(In thousands of dollars)				
Cash Flow Data					
Net cash provided by operating activities	$ 499,046	$ 1,371,409	$ 588,112	$ 674,981	$ 463,334
Net cash (used in) provided by investing activities	(1,280,399)	(227,790)	(2,243,137)	811,999	(168,420)
Net cash provided by (used in) financing activities	471,337	(857,190)	1,679,572	(1,487,633)	(294,907)

	As of December 31,				
	2009	2008 (1)	2007 (2)	2006	2005
	(In thousands of dollars)				
Balance Sheet Data					
Assets					
Cash and cash equivalents	$ 1,859	$ 311,875	$ 25,446	$ 899	$ 1,552
Other current assets	304,776	1,164,566	649,474	183,897	291,780
Property and equipment, net	6,832,722	4,513,396	8,377,227	2,107,524	2,251,887
Goodwill	535,237	535,265	536,822	158,515	173,858
Other assets	60,137	586,813	104,382	12,393	22,865
	$ 7,734,731	$ 7,111,915	$ 9,693,351	$ 2,463,228	$ 2,741,942
Liabilities and Stockholders' Equity					
Current liabilities	$ 682,551	$ 993,645	$ 818,046	$ 460,192	$ 363,998
Long-term debt	2,649,689	2,805,000	3,305,000	235,500	797,375
Other long-term liabilities	269,762	191,534	272,627	170,574	603,422
Deferred income taxes	933,748	744,456	1,959,431	466,279	258,810
Stockholders' equity	3,198,981	2,377,280	3,338,247	1,130,683	718,337
	$ 7,734,731	$ 7,111,915	$ 9,693,351	$ 2,463,228	$ 2,741,942

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

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

(3) At December 31, 2008, our capitalized costs of oil and gas properties exceeded the full cost ceiling and we recorded an impairment of oil and gas properties.

(4) 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.

(5) Represents the gain on the sale of our investment in CVGG.

(6) The derivative instruments we have in place are not classified as hedges for accounting purposes. 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. We used hedge accounting for certain derivative instruments in 2005.

(7) Represents the fee received by us, net of expense, in connection with a terminated merger in 2006.

(8) Cumulative effect of adopting the authoritative guidance for stock based compensation.

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

We also have an interest in an exploration block 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 believe our balanced portfolio of assets, our 2009 deleveraging transactions and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities, including our significant Haynesville Shale acreage position and our Gulf of Mexico exploration discoveries. As of December 31, 2009, we had estimated proved reserves of 359.5 MMBOE, of which 60% was comprised of oil and 64% was proved developed. Our primary sources of liquidity are cash generated from our operations, our senior revolving credit facility and periodic public offerings of debt and equity.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil and 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".

Recent Developments

In August 2009, we amended the participation agreement with Chesapeake to accelerate the payment of the remaining Haynesville Carry. We agreed to pay $1.1 billion for the remaining Haynesville Carry balance due Chesapeake as of September 30, 2009, which we estimated to be $1.25 billion, an approximate 12% reduction. We funded the payment with the net proceeds from the sale of our common stock and the issuance of $400 million 8⅝% Senior Notes due 2019, cash on hand and borrowings from our senior revolving credit facility. Chesapeake committed to drill at least 150 wells per year under the participation agreement for the three-year period beginning October 1, 2009. Additionally, we agreed to terminate our one-time option exercisable in June 2010 which would have relieved us of our obligation to pay the last $800 million of the Haynesville Carry in exchange for an assignment to Chesapeake of 50% of our interest in our Haynesville acreage. As a result of the prepayment of the Haynesville Carry, we will not pay promoted well costs for costs attributable to periods subsequent to the third quarter of 2009. During 2009, we spent $59 million to acquire approximately 5,000 net additional acres in the Haynesville Shale, and at December 31, 2009 we had approximately 111,000 net acres in the Haynesville Shale, including approximately 61,000 net acres of leasehold that we believe is also prospective for the Bossier Shale.

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 oil and gas properties each quarter. Effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, these rules were modified and generally require that we price our future oil and gas production at the twelve-month average first-day-of-the-month reference prices as adjusted for location and quality differentials to determine a ceiling value of our properties compared to prior periods which required end of period prices. 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. The derivative instruments we have in place are not classified as hedges for accounting purposes. The rules require an impairment if our capitalized costs exceed the allowed "ceiling". For further discussion, see "Critical Accounting Policies and Estimates".

Given the volatility of oil and gas prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will change in the near term. If oil and gas prices decline in the future, impairments of our oil and gas properties could occur. Impairment charges required by these rules do not directly impact our cash flows from operating activities.

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 calculated 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, or 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

For the year ended December 31, 2009, we reported net income of $136.3 million, on total revenues of $1.2 billion. This compares to a net loss of $709.1 million on total revenues of $2.4 billion for the year ended December 31, 2008, and net income of $158.8 million on total revenues of $1.3 billion for the year ended December 31, 2007. The 2008 loss includes a $3.6 billion non-cash pre-tax impairment of our oil and gas properties and a $1.6 billion pre-tax mark-to-market gain on derivatives.

Significant transactions which affect comparisons between the periods include:

- the February 2008 divestiture of 50% of our working interest in the Permian and Piceance Basins and all of our working interests in the San Juan Basin and Barnett Shale;
- the divestiture of the remaining 50% of our interest in the Permian and Piceance Basins effective December 1, 2008; and
- the acquisition of Pogo, effective November 6, 2007, and the Piceance Basin properties, effective May 31, 2007.

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,		
	2009	2008	2007
Sales Volumes			
Oil and liquids sales (MBbls)	17,560	20,294	18,124
Gas (MMcf)			
Production	78,184	79,254	29,312
Used as fuel	2,358	2,223	2,302
Sales	75,826	77,031	27,010
MBOE			
Production	30,591	33,503	23,010
Sales	30,198	33,133	22,625
Daily Average Volumes			
Oil and liquids sales (Bbls)	48,110	55,449	49,655
Gas (Mcf)			
Production	214,203	216,540	80,307
Used as fuel	6,461	6,073	6,307
Sales	207,742	210,467	74,000
BOE			
Production	83,811	91,539	63,041
Sales	82,734	90,527	61,986
Unit Economics (in dollars)			
Average NYMEX Prices			
Oil	$ 62.09	$ 99.75	$ 72.36
Gas	3.97	9.06	6.86
Average Realized Sales Price Before Derivative Transactions			
Oil (per Bbl)	$ 51.43	$ 87.05	$ 61.60
Gas (per Mcf)	3.72	8.05	5.68
Per BOE	39.25	72.03	56.12
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 8.31	$ 9.88	$ 9.98
Steam gas costs	1.78	3.96	4.57
Electricity	1.45	1.59	1.76
Production and ad valorem taxes	1.28	2.84	1.44
Gathering and transportation	1.21	0.64	0.50
DD&A (oil and gas properties)	12.79	17.69	12.92

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

	Year Ended December 31,		
	2009	2008	2007
Oil derivatives			
Settlements	$ 141,297	$ (81,447)	$ (103,784)
Monetization of crude oil puts and swaps	1,074,361	-	-
Natural gas derivatives	308,146	47,163	235
	$ 1,523,804	$ (34,284)	$ (103,549)

Comparison of Year Ended December 31, 2009 to Year Ended December 31, 2008

Oil and gas revenues. Oil and gas revenues decreased $1.2 billion, or 50%, to $1.2 billion for 2009 from $2.4 billion for 2008 primarily due to a $32.78 per BOE decrease in average realized prices and a 9% decrease in sales volumes. Excluding the impact of our divestments, increased production from the Haynesville Shale and Flatrock properties is primarily responsible for an 8% increase in sales volumes.

Oil revenues decreased $863.5 million to $903.1 million for 2009 from $1.8 billion in 2008 reflecting lower average realized prices ($722.9 million) and lower sales volumes ($140.6 million). Our average realized price for oil decreased $35.62 to $51.43 per Bbl for 2009 from $87.05 per Bbl for 2008. The decrease is primarily attributable to a decline in NYMEX oil prices, which averaged $62.09 per Bbl in 2009 versus $99.75 per Bbl in 2008. Oil sales volumes decreased 7.3 MBbls per day to 48.1 MBbls per day in 2009 from 55.4 MBbls per day in 2008 primarily reflecting the impact of our divestments in 2008 (6.1 MBbls per day). Excluding the impact of our divestments, production decreased 1.3 MBbls per day primarily due to decreased California volumes as a result of our reduction in drilling capital expenditures, partially offset by higher Gulf of Mexico volumes.

Gas revenues decreased $337.9 million to $282.0 million in 2009 from $619.9 million in 2008 due to lower average realized prices ($333.4 million) and decreased sales volumes ($4.5 million). Our average realized price for gas was $3.72 per Mcf in 2009 compared to $8.05 per Mcf in 2008. Our realized price for gas decreased primarily due to a decrease in the index price for natural gas ($5.09 per Mcf). Gas sales volumes decreased from 210.5 MMcf per day in 2008 to 207.7 MMcf per day in 2009 primarily reflecting the impact of our divestments in 2008 (50.9 MMcf per day). Excluding the impact of our divestments, production increased 30% or 47.1 MMcf per day primarily from the Haynesville and Flatrock properties.

Lease operating expenses. Lease operating expenses decreased $76.5 million, to $250.9 million in 2009 from $327.4 million in 2008. Excluding costs associated with the properties sold in 2008, lease operating costs decreased by $28.1 million, primarily reflecting the implementation of our program to reduce expenses. On a per unit basis, lease operating costs decreased to $8.31 per BOE in 2009 versus $9.88 per BOE in 2008.

Steam gas costs. Steam gas costs decreased $77.4 million, to $53.8 million in 2009 from $131.2 million in 2008, primarily reflecting the lower cost of gas used in steam generation. In 2009, we burned approximately 15.1 Bcf of natural gas at a cost of approximately $3.57 per MMBtu compared to 16.9 Bcf at a cost of approximately $7.78 per MMBtu in 2008.

Electricity. Electricity decreased $8.8 million, to $43.9 million in 2009 from $52.7 million in 2008, primarily reflecting a decrease in rates in California. On a per unit basis, electricity was $1.45 per BOE in 2009 and $1.59 per BOE in 2008.

Production and ad valorem taxes. Production and ad valorem taxes decreased $55.3 million, to $38.7 million in 2009 from $94.0 million in 2008 primarily reflecting lower commodity prices and the divestments in 2008.

Gathering and transportation expenses. Gathering and transportation expenses increased $15.6 million, to $36.7 million in 2009 from $21.1 million in 2008, primarily reflecting an increase in production from our Haynesville Shale and Flatrock properties.

General and administrative expense. G&A expense decreased $8.7 million, to $144.6 million in 2009 from $153.3 million in 2008. The decrease is primarily due to cost reductions in 2009, partially offset by higher stock based compensation expense.

Depreciation, depletion and amortization, or DD&A. DD&A expense decreased $201.2 million, to $407.2 million in 2009 from $608.4 million in 2008 as a result of a lower oil and gas DD&A rate ($164.2 million) and a decrease in production volumes ($37.2 million). Our 2009 DD&A rate was $12.79 per BOE compared to $17.69 per BOE in 2008 reflecting the 2008 year-end impairment of our oil and gas properties.

Impairment of oil and gas properties. At December 31, 2009, the ceiling with respect to our oil and gas properties exceeded the net capitalized costs and we did not record an impairment. In 2008, we recorded a non-cash pre-tax impairment charge of $3.6 billion.

Legal recovery. We received a net recovery of $87.3 million as our share of the $1 billion judgment in the lawsuit Amber Resources Company et al. v. United States in 2009.

Interest expense. Interest expense decreased $43.2 million, to $73.8 million in 2009 from $117.0 million in 2008, primarily due to increased capitalized interest attributable to a higher unevaluated property balance related to our Haynesville Shale leasehold. Interest expense does not include interest capitalized on oil and gas properties not subject to amortization and in the process of development. We capitalized $116.2 million and $71.8 million of interest in 2009 and 2008, respectively.

Debt extinguishment costs. We recorded debt extinguishment costs of $12.1 million and $18.3 million in 2009 and 2008, respectively, in connection with reductions of the commitments under our senior revolving credit facility.

(Loss) gain on mark-to-market derivative contracts. The derivative instruments we have in place are not classified as hedges for accounting purposes. 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.

We recognized a $7.0 million loss in 2009 related to our mark-to-market derivative contracts, which was primarily attributed to a decrease in the fair value of our crude oil puts attributable to higher crude oil prices, partially offset by an increase in the fair value on our natural gas collars as a result of lower natural gas prices. The $1.6 billion mark-to-market gain recognized in 2008 was primarily associated with crude oil puts and natural gas collars. We monetized the crude oil puts in the first quarter of 2009. As a result of this monetization, we received approximately $1.1 billion in net proceeds, which we used to reduce the outstanding balance on our senior revolving credit facility and for other general corporate purposes.

Other income (expense). Other income (expense) for 2009 primarily consists of net MMS royalty refunds related to properties sold by Pogo prior to our acquisition. For 2008, other expense consists primarily of pre-acquisition gas imbalance expenses related to our Pogo acquisition.

Income tax (expense) benefit. Our 2009 income tax expense was $80.9 million, reflecting an annual effective tax rate of 37%, as compared with an income tax benefit of $444.5 million and an effective tax rate of 39% for 2008. Variances in our annual effective tax rate from the 35% federal statutory rate for these years primarily result from the tax effects of permanent differences including expenses that are not deductible because of Internal Revenue Service limitations, the special deduction related to domestic production, state income taxes, tax and financial reporting differences related to noncash employee compensation and changes to our balance of unrecognized tax positions.

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 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 the properties acquired in the Pogo acquisition in November 2007, the Flatrock project in the Gulf of Mexico and the Piceance Basin properties, partially offset by a reduction in 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. Increased service costs were reflective of the higher oil and gas prices during the first nine months of 2008. 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.

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 gas at a cost of approximately $7.78 per MMBtu compared to 16.8 Bcf of gas at a cost of approximately $6.17 per MMBtu in 2007.

Electricity. Electricity increased $12.9 million, to $52.7 million in 2008 from $39.8 million in 2007, primarily reflecting the 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 higher commodity prices.

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 was primarily due to increased personnel and other costs due to the acquisitions in 2007. These expenses were partially offset by an increase in amounts capitalized as part of 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 per BOE compared to $12.92 per BOE 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.

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 the full-cost ceiling, and we recorded a non-cash pre-tax impairment charge of $3.6 billion.

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 in 2008.

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. 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. We recorded $18.3 million of debt extinguishment costs in connection with the reductions of the commitments under our senior revolving credit facility in 2008.

Gain (loss) on mark-to-market derivative contracts. Primarily 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 in 2008 as compared to losses of $88.5 million in 2007. The $1.6 billion mark-to-market gain was primarily associated with our crude oil puts and natural gas collars.

Income tax (expense) benefit. 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 for these years primarily result from the tax effects of permanent differences including expenses that are not deductible because of Internal Revenue Service limitations, the special deduction related to domestic production, state income taxes and changes to our balance of unrecognized tax positions.

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.

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 these 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. While there are signs that the economy may be improving, the potential remains for further volatility and disruption in the capital and credit markets. The recent volatility and disruption have created conditions that may adversely affect the financial condition of lenders in our senior revolving credit facility, the counterparties to our commodity price risk management agreements, our insurers and our oil and natural gas purchasers. These market conditions may adversely affect our liquidity by limiting 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 and equity. At December 31, 2009, we had approximately $989 million available for future secured borrowings under our senior revolving credit facility, which had aggregate commitments and a borrowing base of $1.22 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. Declines in oil and gas prices may adversely affect our liquidity by lowering the amount of the borrowing base that lenders are willing to extend.

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. At December 31, 2009, no single lender's commitment represented more than 7% of our 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. 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 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. As a result of this monetization, we received approximately $1.1 billion in net proceeds, which we used to reduce the outstanding balance on our senior revolving credit facility and for other general corporate purposes. The monetization accelerated cash receipts, while maintaining a hedge position that helps protect against declines in oil and natural gas prices during 2010. See Item 7A – "Quantitative and Qualitative Disclosures About Market Risk".

In addition to monetizing our derivatives, we have continued to strengthen our liquidity during 2009 by issuing new senior notes and shares of our common stock. See "Financing Activities". On September 29, 2009, we used the proceeds from the sale of our common shares, proceeds from the issuance of our $8^5/_8$% Senior Notes, cash on hand and borrowings under our senior revolving credit facility to pay $1.1 billion to Chesapeake for the remaining Haynesville Carry balance. The $1.1 billion payment represented an approximate 12% reduction from the estimated $1.25 billion remaining commitment as of September 30, 2009. The payment allowed us to refinance a shorter-term commitment on a long-term basis.

Our 2010 capital budget is approximately $1.2 billion, including capitalized interest and general and administrative expenses. We intend to fund our 2010 capital budget from internally generated funds and borrowings under our senior revolving credit facility.

We believe that we have sufficient liquidity through our forecasted cash flow from operations and borrowing capacity under our senior revolving credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies and anticipated capital expenditures. 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, 2009, we had a working capital deficit of approximately $375.9 million. We generally have a working capital deficit because we use excess cash to pay down borrowings under our senior revolving credit facility. Our working capital fluctuates for various reasons, including the fair value of our commodity derivative instruments and stock appreciation rights.

Financing Activities

Senior Revolving Credit Facility. In March 2009, we entered into an amendment to our senior revolving credit facility. The amendment reduced the borrowing base and commitments from $2.7 billion and $2.3 billion, respectively, to $1.5 billion in consideration of our derivative monetization. The amendment also increased the cost of borrowing under our senior revolving credit facility. During 2009, the borrowing base and commitments were also reduced as a result of our issuance of $965.0 million of senior notes. At December 31, 2009, our borrowing base and commitments were $1.22 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 our oil and gas properties, reserves, other indebtedness and other relevant factors. Additionally, our senior revolving credit facility contains a $250 million 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 subsidiaries and 65% of the shares 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, 2009, we had $230 million in outstanding borrowings and $1.2 million in letters of credit outstanding under our senior revolving credit facility.

Amounts borrowed under our senior revolving credit facility bear an interest rate, at our election, equal to either: (i) the Eurodollar rate, which is based on LIBOR, plus an additional variable amount ranging from 2.00% to 2.75%; (ii) the greater of (1) the prime rate, as determined by JPMorgan Chase Bank, (2) the federal funds rate, plus ½ of 1%, and (3) the adjusted LIBOR rate plus 1%; or (iii) the over-night federal funds rate plus an additional variable amount ranging from 2.00% to 2.75% 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. Letter of credit fees under our senior revolving credit facility are based on the utilization rate and our long-term debt rating and range from 2.0% to 2.75%. The issuer of any letter of credit receives an issuing fee of 0.125% of the letter of credit exposure. Commitment fees are 0.50% of the amount available for borrowing. The effective interest rate on our borrowings under our senior revolving credit facility was 2.25% at December 31, 2009.

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, 2010, 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, 2010. 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, 2009.

8⅝% Senior Notes. In September 2009, we issued $400 million of 8⅝% Senior Notes due 2019, or 8⅝% Senior Notes, which were sold to the public at 98.335% of the face value to yield 8.875% to maturity. We received approximately $386 million of net proceeds after deducting the underwriting discount, original issue discount and offering expenses. We used the net proceeds for general corporate purposes, including to fund a portion of the remaining Haynesville Carry balance. We may redeem all or part of the 8⅝% Senior Notes on or after October 15, 2014 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to October 15, 2012 we may, at our option, redeem up to 35% of the 8⅝% Senior Notes with the proceeds of certain equity offerings.

10% Senior Notes. In March 2009, we issued $365 million of 10% Senior Notes due 2016, or the 10% Senior Notes, which were sold to the public at 92.373% of the face value to yield 11.625% to maturity. In April 2009, an additional $200 million of 10% Senior Notes due 2016 were sold to the public at 92.969% of the face value, plus interest accrued from March 6, 2009, to yield 11.5% to maturity. We received approximately $330 million and $181 million of net proceeds, respectively, after deducting the underwriting discounts, original issue discount and offering expenses. We used the net proceeds to reduce indebtedness outstanding under our senior revolving credit facility and for general corporate purposes, including capital expenditures. We may redeem all or part of the 10% Senior Notes on or after March 1, 2013 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to March 1, 2012 we may, at our option, redeem up to 35% of the 10% Senior Notes with the proceeds of certain equity offerings.

Our 7¾% Senior Notes due 2015, 10% Senior Notes, 7% Senior Notes due 2017, 7⅝% Senior Notes due 2018 and 8⅝% 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. In the event of a change of control, as defined in the indentures, we will be required to make an offer to repurchase the Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase.

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.

Common Stock Offerings. During the second quarter of 2009, we sold 13.8 million shares of our common stock at a price of $18.70 per share to the public and received $250.9 million of net proceeds after deducting the underwriting discounts and offering expenses. We used the net proceeds for general corporate purposes, including capital expenditures.

During the third quarter of 2009, we sold 17.25 million shares of our common stock at a price of $24.00 per share to the public and received $397.1 million of net proceeds after deducting the underwriting discounts and offering expenses. We used the net proceeds for general corporate purposes, including to fund a portion of the $1.1 billion payment for the Haynesville Carry.

Cash Flows

	Year Ended December 31,		
	2009	2008	2007
	(in millions of dollars)		
Cash provided by (used in):			
Operating activities	$ 499.0	$ 1,371.4	$ 588.1
Investing activities	(1,280.4)	(227.8)	(2,243.1)
Financing activities	471.3	(857.2)	1,679.6

Net cash provided by operating activities was $499.0 million in 2009, $1.4 billion in 2008 and $588.1 million in 2007. The decrease in net cash provided by operating activities in 2009 primarily reflects lower operating income as a result of lower commodity prices. 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.

Net cash used in investing activities of $1.3 billion in 2009 includes additions to oil and gas properties of $1.6 billion and acquisitions of oil and gas properties of $1.2 billion, reflecting the payment of the Haynesville Carry, partially offset by derivative settlements received of $1.5 billion. 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 of $2.2 billion in 2007 reflects 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. 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 provided by financing activities of $471.3 million in 2009 primarily reflects the proceeds of $916.4 million, net of original issue discount of $48.6 million, from the issuance of the 10% and the $8^5/_8$% Senior Notes and the $648.0 million of proceeds from our common stock offerings partially offset by the $1.1 billion net reduction in borrowings under our senior revolving credit facility. Net cash used in financing activities of $857.2 million in 2008 primarily reflects a $900 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 $7^5/_8$% 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. Cash settlements with respect to derivatives that contain a significant financing element are 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 2010, excluding acquisitions, of approximately $1.2 billion, including capitalized interest and general and administrative expenses. We believe that we have sufficient liquidity through our forecasted cash flow from operations and borrowing capacity under our senior revolving credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies and anticipated capital expenditures.

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 may 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 are authorized to expend an additional $695.8 million under this program.

Commitments and Contingencies

We had the following obligations at December 31, 2009 (in thousands):

	Total	2010	2011 and 2012	2013 and 2014	Thereafter
Long-term debt	$ 2,695,000	$ -	$ 230,000	$ -	$ 2,465,000
Interest on debt	1,522,011	216,497	424,764	406,000	474,750
Asset retirement obligation	221,367	7,136	11,240	17,855	185,136
Operating leases	103,494	17,346	29,994	22,928	33,226
Commodity derivative contracts	77,471	71,271	6,200	-	-
Stock compensation awards	39,154	7,474	1,972	-	29,708
Tax uncertainties	17,127	3,243	12,062	-	1,822
Other	7,802	3,279	1,847	827	1,849
	$ 4,683,426	$ 326,246	$ 718,079	$ 447,610	$ 3,191,491

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, 2009 remains outstanding to maturity with interest and commitment fees calculated at the rates in effect at December 31, 2009.

Asset retirement obligations represent the estimated fair value at December 31, 2009 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.

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

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

Stock compensation awards ($7.5 million current and $31.7 million long-term) represent the net liability for the deemed vested portion of SARs and liability-classified restricted stock unit awards. The liability at December 31, 2009 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 will be based on the market price of our common stock at the time the SARs are exercised. See Item 7—"Critical Accounting Policies and Estimates—Stock based compensation".

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

Other obligations primarily represent our liability for environmental remediation obligations.

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 purchases. 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 100 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 be assured that we will be able to collect on these indemnities.

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 100 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. 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 2010 cash expenditures related to plugging, abandonment and remediation will be approximately $7.1 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, $58 million ($114 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 $67 million). To secure its abandonment obligations, the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2009, the escrow account had a balance of $12.7 million. The fair value of our guarantee at December 31, 2009, $0.7 million, considers the payment/performance risk of the purchaser and is included in other long-term liabilities in our 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. While there are signs that the economy may be improving, the potential remains for further volatility and disruption in the capital and credit markets. The recent volatility and disruption have created conditions that 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 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.

Concentration of Credit Risk

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. For a description of purchasers of our oil and gas production that accounted for 10% or more of our total revenues for the three preceding calendar years, see Items 1 and 2 – "Business and Properties—Product Markets and Major Customers".

The six financial institutions that are contract counterparties for our derivative commodity contracts all had Standard & Poor's ratings of A/Negative or better as of December 31, 2009. 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.

There was consolidation in the banking and finance sector during 2009. The commitments under our senior revolving credit facility are from a diverse syndicate of 22 lenders. At December 31, 2009, no single lender's commitments represented more than 7% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

Critical Accounting Policies and Estimates

Management makes many estimates and assumptions in the application of generally accepted accounting principles that may have a material impact on our consolidated financial statements and related disclosures and on the comparability of such information over different reporting periods. All such estimates and assumptions affect reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingent assets and liabilities. Estimates and assumptions are based on information available prior to the issuance of the financial statements. Changes in facts and circumstances or discovery of new information may result in revised estimates and actual results may differ from these estimates.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material. The areas of accounting and the associated critical estimates and assumptions made are discussed below.

Oil and gas reserves. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including DD&A and the full cost ceiling limitation.

In December 2008, the SEC issued its final rule, Modernization of Oil and Gas Reporting, which is effective for reporting 2009 reserve information. The SEC's final rule includes the following provisions:

- provides for reporting oil and gas reserves using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials compared to the year-end prices for prior years;
- permits the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes;

- allows proved undeveloped reserves to be booked beyond one offset location if economic producibility can be established with reasonable certainty;

- generally limits the booking of proved undeveloped reserves to those reserves that are scheduled to be developed within five years;

- requires 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; and

- provides for additional disclosures including reserves preparer and auditor qualifications and optional disclosure of probable and possible reserves in SEC filings.

In January 2010, the FASB issued its authoritative guidance on extractive activities for oil and gas to align its requirements with the SEC's final rule. We adopted the guidance as of December 31, 2009 in conjunction with our year-end reserve report as a change in accounting principle that is inseparable from a change in accounting estimate. Under the SEC's final rule, prior period reserves were not restated. The primary impacts of the SEC's final rule on our reserve estimates include:

- the use of the twelve-month average first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) of $61.18 per Bbl for oil and $3.87 per MMBtu for natural gas compared to the year-end reference prices (prior to adjustment for location and quality differentials) of $79.36 per Bbl for oil and $5.79 per MMBtu for natural gas;

- certain of our undeveloped locations are not scheduled to be developed within five years, which had the impact of reducing our proved undeveloped reserves by 25 MMBOE; and

- we were able to support with reasonable certainty proved undeveloped reserves for certain horizontal locations in the Haynesville Shale, located more than the two parallel offsets from a proved developed well location allowed under the previous guidelines. The impact increased our proved undeveloped reserves by 11 MMBOE.

The impact of the adoption of the SEC's final rule on our financial statements is not practicable to estimate due to the operational and technical challenges associated with calculating a cumulative effect of adoption by preparing reserve reports under both the old and new rules.

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. Future development and abandonment costs are determined annually for each of our properties based upon its 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. 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 subjective, 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. All of our 2009 proved reserve information is based on estimates prepared by outside engineering firms. Estimates prepared by others may be higher or lower than these estimates.

The standardized measure represents estimates only and should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. In accordance with SEC requirements, the estimated discounted future net revenues from proved reserves are generally based on average oil and gas prices in effect for the prior twelve months in 2009 and costs as of the date of the estimate and, in 2008 and 2007, prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the average prices and costs as of the date of the estimate.

Impairments of oil and gas properties. Under the SEC's full cost accounting rules we review the carrying value of our oil and gas properties each quarter. Under these rules, for each cost center, 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 cost of unproved properties not being amortized; plus
- the lower of cost or estimated fair value of unproved properties included in the costs being amortized (net of related tax effects).

These rules were modified as described above in "Oil and gas reserves". Effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, these rules generally require that we price our future oil and gas production at the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Prior to the new rules, we were required to price our future oil and gas production at 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. The derivative instruments we have in place are not classified as hedges for accounting purposes. The rules require an impairment if our capitalized costs exceed this "ceiling". The revised pricing in ceiling test impairment calculations may cause results that are not indicated by market conditions existing at the end of an accounting period. For example, in periods of increasing oil and gas prices, the use of a twelve-month average price in the ceiling test calculation may result in an impairment when the use of the single-day quarter-end price would not. Conversely, in times of declining prices, ceiling test calculations may not result in an impairment that would be reported had the lower single-day quarter-end prices been used.

At December 31, 2009, the ceiling with respect to our oil and gas properties exceeded the net capitalized costs by an insignificant amount and we did not record an impairment. Had the calculation been made using the year-end prices as provided for under the previous rules, the ceiling cushion would have been higher. 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 as a result of the full cost ceiling limitation. Due to significantly depressed oil prices during the first quarter of 2009 and declining gas prices throughout the year, the twelve-month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) were $61.18 per Bbl for oil and $3.87 per MMBtu for natural gas compared to the year-end reference prices of $79.36 per Bbl for oil and $5.79 per MMBtu for natural gas.

Given the volatility of oil and gas prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will change in the near term. If oil and gas prices decline in the future, impairments of our oil and gas properties could occur. Impairments required by these rules do not impact our cash flows from operating activities.

The ceiling limitation is applied separately for each country. We have completed our commitments under our production sharing contract with PetroVietnam, the state oil company of Vietnam, which included the acquisition and interpretation of approximately 850 square kilometers of 3-D seismic data and the drilling of two exploratory wells, which were plugged and abandoned after encountering a minor structurally controlled hydrocarbon accumulation in one well. Our interest in Block 124 covers approximately 1,480,000 gross acres offshore central Vietnam. In the fourth quarter of 2009, we obtained 520 kilometers of 2-D seismic data and the government of Vietnam granted a one-year extension of the first phase of our production sharing contract. We continue to evaluate our plans utilizing the 3-D seismic data, the data from the two exploratory wells and the 2-D seismic data and we expect to finalize our plans during 2010. In the event we discontinue operations, we will record a pre-tax write-down of approximately $58 million, consisting of the accumulated costs in our Vietnam cost center and we would expect to record a corresponding tax deduction for any such write-down.

Oil and natural gas properties not subject to amortization. The cost of unproved oil and natural gas properties are excluded from amortization until the properties are evaluated. 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. Unproved properties are assessed periodically, at least annually, to determine whether impairment has occurred. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment considers the following factors, among others; intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. The transfer of costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on our drilling plans and results, geological and geophysical evaluations, the assignment of proved reserves, availability of capital, and other factors. As of December 31, 2009, we had approximately $3.2 billion of costs excluded from amortization for our U.S. cost center. These costs consist primarily of costs incurred for undeveloped acreage and wells in progress pending determination, together with capitalized interest costs for these projects. Due to the nature of the reserves, the ultimate evaluation of the properties will occur over a period of several years. We expect that 63% of the costs not subject to amortization at December 31, 2009 will be transferred to the amortization base over the next five years and the remainder in the next seven to ten years. The timing of transfer of costs into our amortization base impacts our DD&A rate and full cost ceiling test.

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. See "Oil and gas reserves". 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 as of December 31, 2009 was $15.33 per BOE. Based on our estimated proved reserves and our net oil and gas properties subject to amortization at December 31, 2009: (i) a 5% increase in our costs subject to amortization would increase our DD&A rate by approximately $0.77 per BOE and (ii) a 5% negative revision to proved reserves would increase our DD&A rate by approximately $0.81 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 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. A variety of derivative instruments may be utilized 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. 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.

The derivative instruments we have in place are not classified as hedges for accounting purposes. 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 indices. 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. For asset 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 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 derivative contracts, see Item 7A – "Quantitative and Qualitative Disclosures about Market Risk".

Stock based compensation. Our stock based compensation cost is measured based on the fair value of the award on the grant date and remeasured each reporting period for liability-classified awards. The compensation cost is recognized net of estimated forfeitures over the requisite service period.

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 $61 million, $50 million and $52 million of stock based compensation expense for the years ended December 31, 2009, 2008 and 2007, respectively.

Allocation of purchase price in business combinations. Accounting for business combinations requires the allocation of the purchase price to the various assets and liabilities of the acquired business at their respective fair values. The most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we are required to record the excess as goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to recoverable oil and gas reserves and unproved properties is subject to the full cost ceiling limitation as described in "Impairments of oil and gas properties" above.

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, 2009, goodwill totaled $535 million and represented approximately 7% of our total assets.

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 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.

As discussed above, we follow the full cost method of accounting for oil and gas activities and all of our producing properties are located in the United States. We have determined that for the purpose of performing an impairment test, we have one reporting unit. Quoted market prices in active markets are the best evidence of fair value. In determining the fair value of our reporting unit in the first step of the goodwill impairment test, we apply a control premium to the quoted market price of our common stock. We determine the control premium through reference to control premiums in merger and acquisition transactions for our industry and other comparable industries.

We perform our goodwill impairment test annually as of December 31 and we have recorded no impairment. We also perform interim goodwill impairment tests if events occur or circumstances change that would indicate the fair value of our reporting unit may be below its carrying amount. Due to the adverse market conditions that continued to have a pervasive impact on the U.S. business climate in the first quarter of 2009, we performed an interim goodwill impairment test as of March 31, 2009 and we concluded that our goodwill was not impaired as of that date. 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 June 2009, the FASB issued authoritative guidance for improving financial reporting by enterprises involved with variable interest entities. This guidance eliminates the exemption for qualifying special purpose entities, includes a new approach for determining who should consolidate a variable interest entity, and presents changes as to when it is necessary to reassess who should consolidate a variable interest entity. The guidance is effective for fiscal years beginning after November 15, 2009, and for interim periods within that first annual reporting period. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In January 2010, the FASB issued authoritative guidance that amends the disclosure requirements for fair value measurements. The amendments will provide greater level of disaggregated information and more disclosures about the valuation techniques and inputs to fair value measurements. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disaggregated disclosures related to purchases, sales, issuances and settlements for Level 3 fair value measurements. See Note 6 – "Fair Value Measurements of Assets and Liabilities" in the accompanying financial statements for a discussion of our Level 3 fair value measurements. Those expanded Level 3 disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. This guidance impacts our fair value disclosures associated with our commodity derivative instruments. We early adopted the entire guidance in 2009 and the adoption did not have a material impact on our consolidated financial position, results of operations or cash flows.

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. The derivative instruments we have in place are not classified as hedges for accounting purposes. See Note 5 – "Commodity Derivative Contracts" and Note 6 – "Fair Value Measurements of Assets and Liabilities" in the accompanying financial statements for a discussion of our derivative activities and fair value measurements.

As of December 31, 2009, we had the following outstanding commodity derivative contracts, all of which settle monthly, and none of which were designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price (1)	Average Deferred Premium	Index
Sales of Crude Oil Production					
2010					
Jan - Dec	Put options	40,000 Bbls	$55.00 Strike price	$5.00 per Bbl (2)	WTI
Sales of Natural Gas Production					
2010					
Jan - Dec	Three-way collars (3)	85,000 MMBtu	$6.12 Floor with a $4.64 Limit $8.00 Ceiling	$0.034 per MMBtu	Henry Hub

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

(2) In addition to the deferred premium, a premium averaging $3.86 per barrel was paid from the proceeds of our first quarter 2009 derivative monetization upon entering into these derivative contracts.

(3) If NYMEX is less than the $6.12 per MMBtu floor, we receive the difference between NYMEX and the $6.12 per MMBtu floor up to a maximum of $1.48 per MMBtu. We pay the difference between NYMEX and $8.00 per MMBtu 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 multiplied by the contract volumes less the option premium. If the market price settles at or above the strike price of the put option, we pay only the option premium.

In a typical collar transaction, if the floating price based on a market index is below the floor price in the derivative contract, we receive from the counterparty an amount equal to this difference multiplied by the specified volume. 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 an amount equal to this difference multiplied by the specified volume. We may pay a premium to the counterparty in exchange for a certain floor or ceiling. Any premium reduces amounts we would receive under the floor or increases amounts we would pay above the ceiling. If the floating price exceeds the floor price or is less than the ceiling price, then no payment, other than the premium, is required. If we have less production than the volumes specified under the collar transaction when the floating price exceeds the ceiling price, we must make payments against which there are no offsetting revenues from production.

The fair value of outstanding crude oil and gas commodity derivative instruments at December 31, 2009 and the change in fair value that would be expected from a 10% price increase or decrease is shown below (in millions).

	Fair Value Asset	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil put options	$ 15	$ (6)	$ 11
Natural gas collars	14	(9)	8
	$ 29	$ (15)	$ 19

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.

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 typically 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 48% 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, 2009, $230 million was outstanding under our senior revolving credit facility at an effective interest rate of 2.25%. The carrying value of our senior revolving credit facility approximates fair value, as interest rates are variable, based on prevailing market rates. Based on the $230 million outstanding under our senior revolving credit facility at December 31, 2009, on an annualized basis a 1% change in the effective interest rate would result in a $2.3 million change in our interest costs.

Item 8. *Financial Statements and Supplementary Data*

The information required here is included in this report as set forth in the "Index to Consolidated 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, or 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, 2009 were effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow timely decisions regarding required disclosure.

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, 2009.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009 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, 2009 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 2010 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2009, 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, 2010 and their business experience for the last five years.

Directors

James C. Flores, age 50, 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., or 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 74, 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 became a director of Cullen Frost Bankers, Inc. (formerly Cullen Center Bank & Trust) at its inception in 1969. He became a director of the Frost National Bank in 1994. He served as a director of the boards of Cullen Frost Bankers, Inc. and the Frost National Bank until he retired from both in 2006 and is currently Director Emeritus of both. Mr. Arnold also served on the Audit and Strategic Planning Committees for Cullen Frost Bankers, Inc. from 1995 to 2006. 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 63, Director since March 2003. He retired in January 2003 as Chairman of JPMorgan Chase Bank, South Region, a position he had held since 1998. From 1990 to 1998 he was President of Texas Commerce Bank—Houston, the predecessor entity of JPMorgan Chase Bank. Prior to 1990 Mr. Buckwalter held various executive management positions within the organization. Mr. Buckwalter currently serves on the boards of Service Corporation International, the Texas Medical Center and the Greater Houston Area Red Cross and is Vice Chairman of Torch Securities LLC. He sits on the Nominating and Governance Committee, the Audit Committee and is Chairman of the Compensation Committee for Service Corporation International. Mr. Buckwalter previously served on the board of BCM Technologies, Inc. from 2003 to 2009.

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 69, 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, and is the Chairman of the Audit Committee as well as member of the Management and Compensation Committee and the Reserves Committee. 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 65, Director since November 2007. He was also a director of Pogo Producing Company from 2004 to November 2007. He was the President of National Ocean Industries Association, or NOIA, from December 2000 until January 2010. 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 72, 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 69, Director since November 2007. He was also a director of Pogo from 2005 to November 2007. Dr. Groat currently serves as the Director of both the Center for International Energy and Environment Policy and the Energy and Earth Resources Graduate Program at the University of Texas at Austin. He is also a professor of Geological Sciences and Public Affairs. 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 71, 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 50, 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., or 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 52, 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 47, 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 48, 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 an 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 2010 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 2010 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 2010 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 2010 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, or 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 (incorporated by reference to Exhibit 2.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-31470 (the "2008 10-K")).
2.4	Second Amendment to the Participation Agreement among Plains Exploration & Production Company, PXP Louisiana L.L.C., PXP Louisiana Operations LLC and Chesapeake Louisiana, L.P., dated August 5, 2009 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 7, 2009, File No. 1-31470).
2.5	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).
2.6	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).
2.7	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).
2.8	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 or the April 24, 2007 Form 8-K).

2.9 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).

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, or 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, or 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, or 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 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 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 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 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 filed 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 Ninth Supplemental Indenture, dated March 6, 2009, 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 the Notes) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed March 6, 2009, File No. 1-31470).

4.11 Tenth Supplemental Indenture, dated as of September 11, 2009, to Indenture dated March 13, 2007, among Plains Exploration & Production Company, the subsidiary guarantors parties thereto and Wells Fargo Bank, N.A., as trustee (including form of the Notes) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed September 11, 2009) , File No. 1-31470).

4.12 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).

4.13 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).

4.14 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 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 July 23, 2008, File No. 1-31470).

4.15 Amendment No. 4 to Amended and Restated Credit Agreement, dated as of March 13, 2009, 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 March 13, 2009, 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, or 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).

10.6 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 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 Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-31470, or the September 30, 2006 Form 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 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 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 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 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 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 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 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 2007 10-K).
10.23	Form of Election for Director Deferral of Restricted Stock Awards (incorporated by reference to Exhibit 10.23 to the 2008 10-K).
10.24	Summary of Director Compensation Program (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-31470).
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 & 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.
99.1*	Report of Netherland, Sewell & Associates, Inc., United States locations.
99.2*	Report of Netherland, Sewell & Associates, Inc., Haynesville Shale of Louisiana and Texas.
99.3*	Report of Ryder Scott Company, L.P., Certain Gulf of Mexico Properties.
99.4*	Report of Ryder Scott Company, L.P., Panhandle Properties.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* 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, 2010	/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, 2010	/s/ James C. Flores James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: February 25, 2010	/s/ Isaac Arnold, Jr. Isaac Arnold, Jr., Director
Date: February 25, 2010	/s/ Alan R. Buckwalter, III Alan R. Buckwalter, III, Director
Date: February 25, 2010	/s/ Jerry L. Dees Jerry L. Dees, Director
Date: February 25, 2010	/s/ Tom H. Delimitros Tom H. Delimitros, Director
Date: February 25, 2010	/s/ Thomas A. Fry, III Thomas A. Fry, III, Director
Date: February 25, 2010	/s/ Robert L. Gerry, III Robert L. Gerry, III, Director
Date: February 25, 2010	/s/ Charles G. Groat Charles G. Groat, Director
Date: February 25, 2010	/s/ John H. Lollar John H. Lollar, Director
Date: February 25, 2010	/s/ Winston M. Talbert Winston M. Talbert, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 25, 2010	/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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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 – "Controls and Procedures". 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 1 and 16 to the consolidated financial statements, the Company changed the manner in which it estimates the quantities of oil and gas reserves in 2009 and the limitation on its capitalized costs as of December 31, 2009. As discussed in Note 1 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.

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, 2010

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

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,859	$ 311,875
Accounts receivable	258,585	175,896
Commodity derivative contracts	11,952	945,838
Inventories	19,934	23,368
Prepaid expenses and other current assets	14,305	19,464
	306,635	1,476,441
Property and Equipment, at cost		
Oil and natural gas properties - full cost method		
Subject to amortization	9,044,146	7,106,785
Not subject to amortization	3,279,537	2,513,424
Other property and equipment	125,667	110,990
	12,449,350	9,731,199
Less allowance for depreciation, depletion, amortization and impairment	(5,616,628)	(5,217,803)
	6,832,722	4,513,396
Goodwill	535,237	535,265
Commodity Derivative Contracts	-	530,181
Other Assets	60,137	56,632
	$ 7,734,731	$ 7,111,915
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 248,454	$ 363,713
Commodity derivative contracts	59,176	-
Royalties and revenues payable	78,590	87,874
Interest payable	45,743	20,843
Income taxes payable	-	102,948
Deferred income taxes	153,473	285,426
Other current liabilities	97,115	132,841
	682,551	993,645
Long-Term Debt	2,649,689	2,805,000
Other Long-Term Liabilities		
Asset retirement obligation	214,231	159,473
Other	55,531	32,061
	269,762	191,534
Deferred Income Taxes	933,748	744,456
Commitments and Contingencies (Note 10)		
Stockholders' Equity		
Common stock, $0.01 par value, 250.0 million shares authorized, 143.9 million and 112.9 million shares issued at December 31, 2009 and 2008, respectively	1,439	1,129
Additional paid-in capital	3,381,566	2,739,625
Retained earnings (deficit)	51,204	(85,101)
Accumulated other comprehensive loss	-	(684)
Treasury stock, at cost, 4.5 million shares and 5.3 million shares at December 31, 2009 and 2008, respectively	(235,228)	(277,689)
	3,198,981	2,377,280
	$ 7,734,731	$ 7,111,915

See notes to consolidated financial statements.

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

	Year Ended December 31, 2009	2008	2007
Revenues			
Oil sales	$ 903,146	$ 1,766,677	$ 1,116,376
Gas sales	281,978	619,886	153,416
Other operating revenues	2,006	16,908	3,048
	1,187,130	2,403,471	1,272,840
Costs and Expenses			
Lease operating expenses	250,916	327,412	225,845
Steam gas costs	53,801	131,156	103,464
Electricity	43,891	52,735	39,767
Production and ad valorem taxes	38,708	93,988	32,636
Gathering and transportation expenses	36,651	21,137	11,410
General and administrative	144,586	153,306	124,006
Depreciation, depletion and amortization	407,248	608,448	306,278
Impairment of oil and gas properties	-	3,629,666	-
Accretion	14,332	13,036	9,800
Legal recovery	(87,272)	-	-
Other operating expense	2,136	-	-
	904,997	5,030,884	853,206
Income (Loss) from Operations	282,133	(2,627,413)	419,634
Other Income (Expense)			
Gain on sale of assets	-	65,689	-
Interest expense	(73,811)	(116,991)	(68,908)
Debt extinguishment costs	(12,093)	(18,256)	-
(Loss) gain on mark-to-market derivative contracts	(7,017)	1,555,917	(88,549)
Other income (expense)	27,968	(12,575)	6,322
Income (Loss) Before Income Taxes	217,180	(1,153,629)	268,499
Income tax (expense) benefit			
Current	(45,091)	(230,815)	4,677
Deferred	(35,784)	675,350	(114,425)
Net Income (Loss)	$ 136,305	$ (709,094)	$ 158,751
Earnings (Loss) Per share			
Basic	$ 1.10	$ (6.52)	$ 2.02
Diluted	$ 1.09	$ (6.52)	$ 1.99
Weighted Average Shares Outstanding			
Basic	124,405	108,828	78,627
Diluted	125,288	108,828	79,808

See notes to consolidated financial statements.

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

	Year Ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 136,305	$ (709,094)	$ 158,751
Items not affecting cash flows from operating activities			
Gain on sale of assets	-	(65,689)	-
Depreciation, depletion and amortization	407,248	608,448	306,278
Impairment of oil and gas properties	-	3,629,666	-
Accretion	14,332	13,036	9,800
Deferred income tax expense (benefit)	35,784	(675,350)	114,425
Debt extinguishment costs	12,093	18,256	-
Loss (gain) on mark-to-market derivative contracts	7,017	(1,555,917)	88,549
Noncash compensation	60,490	50,401	52,019
Other noncash items	6,950	6,546	707
Change in assets and liabilities from operating activities, net of effect of acquisitions			
Accounts receivable and other assets	(26,600)	120,761	(65,694)
Inventories	760	(4,782)	(530)
Accounts payable and other liabilities	(46,751)	(109,182)	53,351
Stock appreciation rights	(355)	(59,078)	(8,322)
Income taxes (receivable) payable	(108,227)	103,387	(121,222)
Net cash provided by operating activities	499,046	1,371,409	588,112
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to oil and gas properties	(1,628,357)	(1,116,715)	(770,409)
Acquisition of oil and gas properties	(1,159,939)	(2,006,127)	(975,407)
Acquisition of Pogo Producing Company, net of cash acquired	-	(77,686)	(298,031)
Proceeds from sales of oil and gas properties and related assets, net of costs and expenses	-	2,969,945	-
Derivative settlements	1,522,412	(8,606)	(99,861)
Decrease (increase) in restricted cash	-	59,092	(59,092)
Additions to other property and equipment	(14,677)	(44,436)	(36,176)
Other	162	(3,257)	(4,161)
Net cash used in investing activities	(1,280,399)	(227,790)	(2,243,137)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from revolving credit facilities	3,513,325	14,331,046	4,745,100
Repayments of revolving credit facilities	(4,588,325)	(15,231,046)	(2,775,600)
Proceeds from issuance of Senior Notes	916,439	400,000	1,100,000
Redemption of long-term debt	-	-	(1,291,926)
Costs incurred in connection with financing arrangements	(19,556)	(27,527)	(47,333)
Derivative settlements	1,392	(25,678)	(3,688)
Issuance of common stock	648,005	-	-
Purchase of treasury stock	-	(304,192)	(47,485)
Other	57	207	504
Net cash provided by (used in) financing activities	471,337	(857,190)	1,679,572
Net (decrease) increase in cash and cash equivalents	(310,016)	286,429	24,547
Cash and cash equivalents, beginning of period	311,875	25,446	899
Cash and cash equivalents, end of period	$ 1,859	$ 311,875	$ 25,446

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2009	2008	2007
Net Income (Loss)	$ 136,305	$ (709,094)	$ 158,751
Other Comprehensive Income (Loss)			
Pension liability adjustment	1,094	(3,616)	2,522
Pension related tax (expense) benefit	(410)	1,366	(956)
	684	(2,250)	1,566
Comprehensive Income (Loss)	$ 136,989	$ (711,344)	$ 160,317

See notes to consolidated financial statements.

PLAINS EXPLORATION & 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 (Loss)	Treasury Stock		Total
	Shares	Amount				Shares	Amount	
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 purchases	-	-	-	-	-	(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
Net income	-	-	-	136,305	-	-	-	136,305
Issuance of common stock	31,050	310	647,695	-	-	-	-	648,005
Restricted stock awards	-	-	36,630	-	-	-	-	36,630
Issuance of treasury stock for restricted stock awards	-	-	(42,441)	-	-	765	42,461	20
Other comprehensive income	-	-	-	-	684	-	-	684
Exercise of stock options and other	-	-	57	-	-	6	-	57
Balance at December 31, 2009	143,924	$ 1,439	$ 3,381,566	$ 51,204	$ -	(4,512)	$ (235,228)	$ 3,198,981

See notes to consolidated financial statements.

Note 1 — Summary of Significant Accounting Policies

General. Plains Exploration & Production Company, a Delaware corporation formed in 2002 ("PXP", the "Company", "us", "our", or "we"), is an independent energy company 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 an interest in an exploration block offshore Vietnam.

Our consolidated financial statements include the accounts of all our 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. Events subsequent to December 31, 2009 were evaluated until the time this Form 10-K was filed with the Securities and Exchange Commission, or SEC, on February 25, 2010.

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; (3) timing of transfers from oil and gas properties not subject to amortization; (4) allocating purchase price in connection with business combinations and determining fair value, including goodwill; (5) income taxes; (6) accrued assets and liabilities; (7) stock based compensation; (8) asset retirement obligations and (9) valuation of derivative instruments. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results may differ from these estimates.

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 oil and gas 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. See Note 16 - Oil and Natural Gas Activities-Capitalized Costs. 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 capitalized costs and proved reserves of oil and gas attributable to a cost center, in which case a gain or loss is recognized.

Under the SEC's full cost accounting rules, we review the carrying value of our oil and gas properties each quarter on a country-by-country basis. Under these rules, for each cost center, 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 cost of unproved properties not being amortized; plus
- the lower of cost or estimated fair value of unproved properties included in the costs being amortized (net of related tax effects).

These rules were modified as discussed in Note 16 - Oil and Natural Gas Activities. Effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, these rules generally require that we price our future oil and gas production at the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Our reference prices are the West Texas Intermediate spot price for oil and the Henry Hub spot price for gas. Prior to the new rules, we were required to 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. The reserve estimates exclude the effect of any derivatives we have in place. The rules require an impairment if our capitalized costs exceed this "ceiling".

Asset Retirement Obligation. We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with an offsetting increase to proved oil and gas properties. 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. Each period we accrete the liability to its then present value and depreciate the capitalized cost over the useful life of the related asset.

Other Property and Equipment. Other property and equipment is recorded at cost and consists primarily of land and real estate development costs, aircraft, office furniture and fixtures and computer hardware and software. Acquisitions, renewals, and betterments are capitalized; maintenance and repairs are expensed. Depreciation is calculated 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.

Cash and Cash Equivalents. Cash and cash equivalents consisted primarily of highly liquid money market mutual funds that hold U.S. government securities and demand deposits with financial institutions. The mutual funds are available to us upon demand. Accounts payable at December 31, 2009 and 2008 included $5.3 million and $19.1 million, respectively, representing outstanding checks that had not been presented for payment.

Restricted Cash. Restricted cash consisted of certain amounts payable to former Pogo Producing Company, or Pogo, executives, which was 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 consisted of the following (in thousands):

	December 31, 2009	December 31, 2008
Oil	$ 6,488	$ 6,689
Materials and supplies	13,446	16,679
	$ 19,934	$ 23,368

Federal and State Income Taxes. We recognize deferred tax liabilities and assets for 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 have also established a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is 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 recognized is the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. Furthermore, we recognize potential penalties and interest related to unrecognized tax benefits as a component of income tax expense. See Note 9 - Income Taxes.

Revenue Recognition. Oil and gas revenue from our interests in producing wells is recognized upon delivery and passage of title using the sales method for gas imbalances, net of any royalty interests or other profit interests in the produced product. 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 unless the amount taken by other parties exceeds the estimate of their remaining reserves. We had no material gas imbalances at December 31, 2009 or 2008.

Derivative Financial Instruments. We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. We do not enter into derivative instruments for speculative trading purposes. We present the fair value of our derivative contracts on a net basis where the right of offset is provided for in our counterparty agreements. See Note 5 - Commodity Derivative Contracts.

Fair Value. Effective January 1, 2008, we adopted the Financial Accounting Standard Board's, or FASB's, authoritative guidance that defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. The new guidance did not require any new fair value measurements; however, pursuant to the adoption of this guidance, we revised our fair value calculations to consider our credit quality and the credit quality of our counterparties.

Fair value is the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants. The authoritative guidance characterizes inputs used in determining fair value according to a hierarchy that prioritizes inputs based upon the degree to which they are observable. The three levels of the fair value hierarchy 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. If the asset or liability has a specified contractual term, the Level 2 input must be observable 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 and determine their placement within the fair value hierarchy levels as described above. See Note 6 – Fair Value Measurements of Assets and Liabilities.

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, 2009, goodwill totaled $535 million and represented approximately 7% of our total assets.

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 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.

As discussed above, we follow the full cost method of accounting for oil and gas activities and all of our producing properties are located in the United States. We have determined that for the purpose of performing an impairment test, we have one reporting unit. Quoted market prices in active markets are the best evidence of fair value. In determining the fair value of our reporting unit in the first step of the goodwill impairment test, we apply a control premium to the quoted market price of our common stock. We determine the control premium through reference to control premiums in acquisition transactions for our industry and other comparable industries.

We perform our goodwill impairment test annually as of December 31 and have recorded no impairment. 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 continued to have a pervasive impact on the U.S. business climate in the first quarter of 2009, we performed an interim goodwill impairment test as of March 31, 2009 and we concluded that our goodwill was not impaired as of that date. 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.

Business Segment Information. We acquire, develop, explore for and produce oil and gas primarily in the United States. 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 block offshore Vietnam that has no proved reserves, oil and gas production or sales. Capitalized costs consisted of $58 million of costs not subject to amortization as of December 31, 2009. Accordingly, no geographic data is presented for our international operations.

Stock Based Compensation. Our stock based compensation cost is measured based on the fair value of the award on the grant date and remeasured each reporting period for liability-classified awards. The compensation cost is recognized net of estimated forfeitures over the requisite service period. See Note 8 - Stock Based and Other Compensation Plans.

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 terminated the plan and in May 2009, we made final lump sum distributions and annuity purchases in settlement of the plan's obligations and recognized in income the remaining balance in accumulated other comprehensive loss.

Recent Accounting Pronouncements. In June 2009, the FASB issued authoritative guidance for improving financial reporting by enterprises involved with variable interest entities. This guidance eliminates the exemption for qualifying special purpose entities, includes a new approach for determining who should consolidate a variable interest entity and presents changes as to when it is necessary to reassess who should consolidate a variable interest entity. The guidance is effective for fiscal years beginning after November 15, 2009 and for interim periods within that first annual reporting period. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In January 2010, the FASB issued authoritative guidance that amends the disclosure requirements for fair value measurements. The amendments will provide a greater level of disaggregated information and more disclosures about the valuation techniques and inputs to fair value measurements. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disaggregated disclosures related to purchases, sales, issuances and settlements for Level 3 fair value measurements. For further discussion of Level 3 fair value measurements, see "*Fair Value*". The expanded Level 3 disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. This guidance impacts our fair value disclosures associated with our commodity derivative instruments. We early adopted the entire guidance in 2009 and the adoption did not have a material impact on our consolidated financial position, results of operations or cash flows.

Note 2 — Acquisitions

Chesapeake Participation Agreement

In July 2008, we acquired from a subsidiary of Chesapeake Energy Corporation, or 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, which we refer to as the Haynesville Carry. 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. At the acquisition date, there were no material proved reserves associated with the leasehold interests acquired.

In August 2009, we amended the participation agreement with Chesapeake to accelerate the payment of the remaining Haynesville Carry. On September 29, 2009, we paid $1.1 billion to Chesapeake for the remaining Haynesville Carry balance as of September 30, 2009, which we estimated to be $1.25 billion, an approximate 12% reduction. We funded the payment with net proceeds from the sale of our common stock and the issuance of $400 million of $8^5/_8$% Senior Notes due 2019, cash on hand and borrowings from our senior revolving credit facility. Chesapeake committed to drill at least 150 wells per year under the participation agreement for the three-year period beginning October 1, 2009. Additionally, we agreed to terminate our one-time option exercisable in June 2010, which would have relieved us of our obligation to pay the last $800 million of the Haynesville Carry in exchange for an assignment to Chesapeake of 50% of our interest in our Haynesville acreage. As a result of the prepayment of the Haynesville Carry, we will not pay promoted well costs for costs attributable to periods subsequent to the third quarter of 2009. During 2009, we spent $59 million to acquire approximately 5,000 net additional acres in the Haynesville Shale, and at December 31, 2009 we had approximately 111,000 net acres in the Haynesville Shale, including approximately 61,000 net acres of leasehold that we believe is also prospective for the Bossier Shale.

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 3 - Divestments.

Pogo Producing Company

In November 2007, we acquired Pogo in a stock and cash transaction, or 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 $35.4 million to redeem outstanding stock options. The total purchase price included $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 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 cash portion of the purchase price was funded by borrowings under our senior revolving credit facility.

Piceance Basin Properties

Piceance Acquisition. In May 2007, we acquired certain properties located in the Piceance Basin, or 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, or CVGG. We financed the cash portion of the acquisition using our senior revolving credit facility.

Piceance Basin Expansion. In June 2008, PXP and a subsidiary of Occidental Petroleum Corporation, or 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 in June 2008, with the remaining installments totaling $59.1 million.

In February 2008, we sold 50% of our interest in the oil and gas properties acquired in the May 2007 Piceance acquisition to Oxy and in December 2008, we sold our remaining interest in the oil and gas properties acquired in the May 2007 Piceance Basin acquisition and our interest in the Piceance Basin expansion to Oxy. See Note 3 - Divestments. 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 due 2017.

We believe the assumptions used provide a reasonable basis for presenting the pro forma significant effects directly attributable to the Pogo and Piceance acquisitions. This unaudited pro forma information assumes such transactions occurred on January 1, 2007. This pro forma financial information does not purport to represent what our results of operations would have been if such transactions had occurred on that date.

	Year Ended December 31, 2007
	(in thousands, except per share data) (unaudited)
Revenues	$ 2,022,599
Income from operations	396,841
Income from continuing operations	74,422
Net income	74,422
Basic and diluted earnings per share	
Basic	
Income from continuing operations	$ 0.66
Net income	0.66
Diluted	
Income from continuing operations	0.65
Net income	0.65
Weighted average shares outstanding	
Basic	113,066
Diluted	114,247

Note 3 — Divestments

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. 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 2 - Acquisitions. 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., or 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.

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 $1.23 billion in cash proceeds, after closing adjustments. We sold the remaining 50% of our working interests in oil and gas properties located in the Permian and Piceance Basins, including a 50% interest in the entity that held our interest in CVGG. 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 2 - Acquisitions. We recorded a $35.1 million pretax gain on the sale of the 50% interest in the entity that held our interest in CVGG.

The proceeds from the 2008 sales of oil and gas properties were recorded as reductions to capitalized costs pursuant to full cost accounting rules.

Note 4 — Long-Term Debt

At December 31, 2009 and 2008, long-term debt consisted of (in thousands):

	December 31, 2009	December 31, 2008
Senior revolving credit facility	$ 230,000	$ 1,305,000
7 3/4% Senior Notes due 2015	600,000	600,000
10% Senior Notes due 2016 (less unamortized discount of $38.8 million)	526,222	-
7% Senior Notes due 2017	500,000	500,000
7 5/8% Senior Notes due 2018	400,000	400,000
8 5/8% Senior Notes due 2019 (less unamortized discount of $6.5 million)	393,467	-
	$ 2,649,689	$ 2,805,000

Aggregate total maturities of long-term debt in the next five years are $230 million in 2012.

Senior Revolving Credit Facility. In March 2009, we entered into an amendment to our senior revolving credit facility. The amendment reduced the borrowing base and commitments from $2.7 billion and $2.3 billion, respectively, to $1.5 billion in consideration of our derivative monetization. See Note 5 – Commodity Derivative Contracts. The amendment also increased the cost of borrowing under our senior revolving credit facility. During 2009, the borrowing base and commitments were also reduced as a result of our issuance of $965.0 million of senior notes. At December 31, 2009, our borrowing base and commitments were $1.22 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 our oil and gas properties, reserves, other indebtedness and other relevant factors. Additionally, our senior revolving credit facility contains a $250 million 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 subsidiaries and 65% of the shares of stock in certain foreign subsidiaries and mortgages covering at least 75% of the total present value of our domestic oil and gas properties. At December 31, 2009, we had $1.2 million in letters of credit outstanding under our senior revolving credit facility.

Amounts borrowed under our senior revolving credit facility bear an interest rate, at our election, equal to either: (i) the Eurodollar rate, which is based on LIBOR, plus an additional variable amount ranging from 2.00% to 2.75%; (ii) the greater of (1) the prime rate, as determined by JPMorgan Chase Bank, (2) the federal funds rate, plus ½ of 1%, and (3) the adjusted LIBOR rate plus 1%; or (iii) the over-night federal funds rate plus an additional variable amount ranging from 2.00% to 2.75% 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. Letter of credit fees under our senior revolving credit facility are based on the utilization rate and our long-term debt rating and range from 2.0% to 2.75%. The issuer of any letter of credit receives an issuing fee of 0.125% of the undrawn amount. Commitment fees are 0.50% of the amount available for borrowing. The effective interest rate on our borrowings under our senior revolving credit facility was 2.25% at December 31, 2009.

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, 2010, 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, 2010. 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, 2009.

8⅝% Senior Notes. In September 2009, we issued $400 million of 8⅝% Senior Notes due 2019, or the 8⅝% Senior Notes, which were sold to the public at 98.335% of the face value to yield 8.875% to maturity. We received approximately $386 million of net proceeds after deducting the underwriting discount, original issue discount and offering expenses. We used the net proceeds for general corporate purposes, including to fund a portion of the remaining Haynesville Carry balance. See Note 2 – Acquisitions. We may redeem all or part of the 8⅝% Senior Notes on or after October 15, 2014 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to October 15, 2012 we may, at our option, redeem up to 35% of the 8⅝% Senior Notes with the proceeds of certain equity offerings.

10% Senior Notes. In March 2009, we issued $365 million of 10% Senior Notes due 2016, or the 10% Senior Notes, which were sold to the public at 92.373% of the face value to yield 11.625% to maturity. In April 2009, an additional $200 million of 10% Senior Notes due 2016 were sold to the public at 92.969% of the face value, plus interest accrued from March 6, 2009, to yield 11.5% to maturity. We received approximately $330 million and $181 million of net proceeds, respectively, after deducting the underwriting discounts, original issue discount and offering expenses. We used the net proceeds to reduce indebtedness outstanding under our senior revolving credit facility and for general corporate purposes, including capital expenditures. We may redeem all or part of the 10% Senior Notes on or after March 1, 2013 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to March 1, 2012 we may, at our option, redeem up to 35% of the 10% Senior Notes with the proceeds of certain equity offerings.

7⅝% Senior Notes. In May 2008, we issued $400 million of 7⅝% Senior Notes due 2018, or the 7⅝% Senior Notes, at par. We used the proceeds of this offering to reduce debt under our senior revolving credit facility. 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.

7¾% Senior Notes. In June 2007, we issued $600 million principal amount of 7¾% Senior Notes due 2015, or 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.

7% Senior Notes. In March 2007, we issued $500 million principal amount of 7% Senior Notes due 2017, or 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.

Our 7¾% Senior Notes, 10% Senior Notes, 7% Senior Notes, 7⅝% Senior Notes and 8⅝% 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. In the event of a change of control, as defined in the indentures, we will be required to make an offer to repurchase the Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

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.

Debt Extinguishment Costs. During 2009 and 2008, we recognized $12.1 million and $18.3 million, respectively, of debt extinguishment costs in connection with the reductions in our borrowing base and commitments under our senior revolving credit facility.

Pogo Tender Offers and Consent Solicitations for Senior Subordinated Notes of Pogo. Prior to its acquisition by PXP, Pogo initiated a tender offer at 104% for the $450 million of its outstanding 7.875% Senior Subordinated Notes due 2013, 103% for the $300 million of its outstanding 6.625% Senior Subordinated Notes due 2015 and 103% for the $500 million of its outstanding 6.875% Senior Subordinated Notes due 2017. In November and December 2007, we completed the redemption of all $450 million of outstanding 7.875% Senior Subordinated Notes, all $300 million of outstanding 6.625% Senior Subordinated Notes and over 99% of the $500 million of outstanding 6.875% 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 5 — Commodity Derivative Contracts

General

We are exposed to various market risks, including volatility in oil and gas commodity prices, interest rates and foreign currency exchange rates. The level of derivative activity we engage in depends on our view of market conditions, available derivative prices and operating strategy. A variety of derivative instruments, such as swaps, collars, puts, calls and various combinations of these instruments, may be utilized to manage our exposure to the volatility of oil and gas commodity prices. 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.

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 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. The derivative instruments we have in place are not classified as hedges for accounting purposes.

Cash settlements with respect to derivatives that contain a significant financing element are 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 multiplied by the contract volumes less the option premium. If the market price settles at or above the strike price of the put option, we pay only the option premium.

In a typical collar transaction, if the floating price based on a market index is below the floor price in the derivative contract, we receive from the counterparty an amount equal to this difference multiplied by the specified volume. 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 an amount equal to the difference multiplied by the specified volume. We may pay a premium to the counterparty in exchange for a certain floor or ceiling. Any premium reduces amounts we would receive under the floor or increases amounts we would pay above the ceiling. If the floating price exceeds the floor price or is less than the ceiling price, then no payment, other than the premium, is required. If we have less production than the volumes 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.

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 terminated our crude oil swaps on 20,000 BOPD in 2009. As a result of this monetization, we received approximately $1.1 billion in net proceeds, which we used to reduce the outstanding balance on our senior revolving credit facility and for other general corporate purposes.

See Note 6 - Fair Value Measurements of Assets and Liabilities, for additional discussion on the fair value measurement of our derivative contracts.

As of December 31, 2009, we had the following outstanding commodity derivative contracts, all of which settle monthly, and none of which were designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price (1)	Average Deferred Premium	Index
Sales of Crude Oil Production					
2010					
Jan - Dec	Put options	40,000 Bbls	$55.00 Strike price	$5.00 per Bbl (2)	WTI
Sales of Natural Gas Production					
2010					
Jan - Dec	Three-way collars (3)	85,000 MMBtu	$6.12 Floor with a $4.64 Limit $8.00 Ceiling	$0.034 per MMBtu	Henry Hub

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

(2) In addition to the deferred premium, a premium averaging $3.86 per barrel was paid from the proceeds of our first quarter 2009 derivative monetization upon entering into these derivative contracts.

(3) If NYMEX is less than the $6.12 per MMBtu floor, we receive the difference between NYMEX and the $6.12 per MMBtu floor up to a maximum of $1.48 per MMBtu. We pay the difference between NYMEX and $8.00 per MMBtu if NYMEX is greater than the $8.00 ceiling.

Balance Sheet

At December 31, 2009 and 2008, we had the following outstanding commodity derivative contracts, none of which were designated as hedging instruments, recorded in our consolidated balance sheets (in thousands):

Instrument Type	Balance Sheet Classification	Estimated Fair Value Year Ended December 31, 2009	2008
Crude oil puts	Commodity derivative contracts - current assets	$ 15,173	$ 882,179
Crude oil swaps	Commodity derivative contracts - current assets	-	5,124
Natural gas collars	Commodity derivative contracts - current assets	14,312	215,391
Crude oil puts	Commodity derivative contracts - non-current assets	-	693,148
Total derivative instruments		$ 29,485	$ 1,795,842

The following table provides supplemental information to reconcile the fair value of our derivative assets to our consolidated balance sheets at December 31, 2009 and 2008, considering the deferred premiums and accrued interest and related settlement (payable) receivable amounts which are not included in the fair value amounts disclosed in the table above (in thousands):

	Year Ended December 31, 2009	Year Ended December 31, 2008
Net fair value asset	$ 29,485	$ 1,795,842
Deferred premium and accrued interest on derivative contracts	(73,305)	(333,156)
Settlement (payable) receivable	(3,404)	13,333
Net commodity derivative (liability) asset	$ (47,224)	$ 1,476,019
Commodity derivative contracts - current asset	$ 11,952	$ 945,838
Commodity derivative contracts - non-current asset	-	530,181
Commodity derivative contracts - current liability	(59,176)	-
	$ (47,224)	$ 1,476,019

We present the fair value of our derivative contracts on a net basis where the right of offset is provided for in our counterparty agreements.

Income Statement

During the years ended December 31, 2009, 2008 and 2007, pre-tax amounts recognized in our consolidated statements of income for derivative transactions were as follows (in thousands):

	Year Ended December 31, 2009	2008	2007
(Loss) gain on mark-to-market derivative contracts	$ (7,017)	$ 1,555,917	$ (88,549)

Cash Payments and Receipts

During the years ended December 31, 2009, 2008 and 2007, cash receipts (payments) for derivatives were as follows (in thousands):

	Year Ended December 31, 2009	2008	2007
Oil derivatives			
Settlements	$ 141,297	$ (81,447)	$ (103,784)
Monetization of crude oil puts and swaps	1,074,361	-	-
Natural gas derivatives	308,146	47,163	235
	$ 1,523,804	$ (34,284)	$ (103,549)

Credit Risk

We generally do not require collateral or other security to support derivative instruments subject to credit risk. However, the agreements with each of the counterparties to our derivative instruments contain netting provisions within the agreements. If a default occurs under the agreements, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contracts with the amount due from the defaulting party under the derivative contracts. As a result of the netting provisions under the agreements, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that we would have incurred if all the counterparties to our derivative contracts failed to perform according to the terms of the derivative contracts at December 31, 2009, was $12.0 million.

Contingent Features

The counterparties to our commodity derivative contracts consist of six financial institutions. Our counterparties 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 senior revolving credit facility. Therefore, we are not generally required to post additional collateral under our derivative agreements.

Certain of our derivative 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 at that time. As of December 31, 2009, we were in a net liability position with three of the counterparties to our derivative instruments, totaling $58.6 million.

Note 6 — Fair Value Measurements of Assets and Liabilities

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. We follow a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Our commodity derivative instruments are recorded at fair value on a recurring basis in our consolidated balance sheets with the changes in fair value recorded in our consolidated statements of income. The following table presents, for each fair value hierarchy level, our commodity derivative assets and liabilities measured at fair value on a recurring basis as of December 31, 2009 and 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 contracts				
2009				
Crude oil puts	$ 15,173	$ -	$ 15,173	$ -
Natural gas collars	14,312	-	-	14,312
	$ 29,485	$ -	$ 15,173	$ 14,312
2008				
Crude oil puts	$ 1,575,327	$ -	$ -	$ 1,575,327
Crude oil swaps	5,124	-	5,124	-
Natural gas collars	215,391	-	-	215,391
	$ 1,795,842	$ -	$ 5,124	$ 1,790,718

(1) Option premium and accrued interest of $73.3 million in 2009 and $333.2 million in 2008 and settlement payable of $3.4 million in 2009 and settlement receivable of $13.3 million in 2008 are not included in the fair value of derivatives.

The fair value amounts of our derivative instruments are estimated using an option-pricing model, which 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. For asset balances, we use the credit default swap value for counterparties when available, or the spread between the risk-free interest rate 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 derivatives that have identical assets or liabilities with quoted, unadjusted prices in active markets as Level 1. We classify our derivatives as Level 2 if the inputs used in the valuation model are directly or indirectly observable for substantially the full term of the instrument; however, if the significant inputs are not observable for substantially the full term of the instrument, we classify those derivatives as Level 3. We determine whether the market for our derivative instruments is active or inactive based on transaction volume for such instruments and classify as Level 3 those instruments that are not actively traded. For these inputs, we utilize pricing and volatility information from other instruments with similar characteristics and extrapolate data between data points for thinly traded instruments. As of December 31, 2009, our crude oil put options are classified as Level 2, and our natural gas collars are classified as Level 3 instruments. We determine the appropriate level for each financial asset and liability on a quarterly basis and recognize any transfers at the beginning of the reporting period.

The following table presents a reconciliation of changes in fair value of financial assets and liabilities classified as Level 3 for the years ended December 31, 2009 and 2008 (in thousands):

	Year Ended December 31,	
	2009 (1)	**2008** (1)
Fair value at beginning of period	$ 1,790,718	$ -
Transfers (2)	(124,690)	3,429
Realized and unrealized gains included in earnings (3)	226,186	1,544,873
Purchases	1,038	297,247
Settlements	(1,878,940)	(54,831)
Fair value at end of period	$ 14,312	$ 1,790,718
Change in unrealized gains and losses relating to assets and liabilities held as of the end of the period (3)	$ 13,274	$ 1,499,370

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

(2) During the first quarter of 2009, the inputs used to value our $55 crude put options were directly or indirectly observable and our $55 crude puts were transferred to Level 2. During the fourth quarter of 2008, the inputs used to value our $55 crude put options were not directly or indirectly observable and we classified them as Level 3.

(3) Realized and unrealized gains included in earnings for the period are reported as mark-to-market derivative contracts in our consolidated statements of income.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Nonfinancial assets and liabilities, such as goodwill and other property and equipment, are measured at fair value on a nonrecurring basis upon impairment; however, we have no material assets or liabilities that are reported at fair value on a nonrecurring basis in our consolidated balance sheets.

Fair Value of Other Financial Instruments

Authoritative guidance on financial instruments requires certain fair value disclosures, such as those on our long-term debt, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

The carrying values of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. Derivative financial instruments included in our consolidated balance sheets are stated at fair value; however, certain of our derivative financial instruments have a deferred premium, including our crude oil put option contracts and natural gas collars. The deferred premium reduces the asset or increases the liability depending on the fair value of the derivative financial instrument.

The carrying amounts and fair values of our other financial instruments are as follows (in thousands):

	December 31, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Current Liability				
Deferred premium and accrued interest on derivative contracts	$ 73,305	$ 73,305	$ 170,189	$ 170,189
Non-Current Liability				
Deferred premium and accrued interest on derivative contracts	-	-	162,967	162,967
Long-Term Debt				
Senior revolving credit facility	230,000	230,000	1,305,000	1,125,945
7¾% Senior Notes	600,000	610,500	600,000	453,000
10% Senior Notes	526,222	618,675	-	-
7% Senior Notes	500,000	491,250	500,000	342,500
7⅝% Senior Notes	400,000	409,000	400,000	274,000
8⅝% Senior Notes	393,467	411,000	-	-

The fair value of our Senior Notes is based on quoted market prices from trades of such debt. The carrying value of our senior revolving credit facility as of December 31, 2009 approximates fair value, as interest rates are variable, based on prevailing market rates. Additionally, our credit spread is reflective of the market due to the amendment in the first quarter of 2009, which adjusted our spread to reflect prevailing market rates. As of December 31, 2008, the fair value of our senior revolving credit facility was based on rates then available for debt instruments with similar terms and average maturities from companies with similar credit ratings in our industry.

Note 7 — Asset Retirement Obligation

The following table reflects the changes in our asset retirement obligation during the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Asset retirement obligation - beginning of period	$ 169,809	$ 195,408	$ 137,311
Liabilities incurred in acquisitions	-	1,697	54,349
Property dispositions and other	-	(29,236)	-
Settlements	(3,699)	(6,907)	(2,396)
Change in estimate	39,518	(7,571)	(6,900)
Accretion expense	14,332	13,036	9,800
Asset retirement additions	1,407	3,382	3,244
Asset retirement obligation - end of period (1)	$ 221,367	$ 169,809	$ 195,408

(1) $7.1 million and $10.3 million are included in other current liabilities at December 31, 2009 and 2008, respectively.

Our change in estimate during 2009 is attributable to increased costs to plug and abandon wells and retire equipment, primarily in our California fields, and a change in estimated useful lives of certain offshore platforms for which we retain the asset retirement obligation.

Note 8 — Stock Based and Other Compensation Plans

We have three stock incentive plans: the 2002 Stock Incentive Plan, or 2002 Plan, which provides for a maximum of 1.5 million shares available for awards; the 2004 Stock Incentive Plan, or 2004 Plan, which provides for a maximum of 8.4 million shares available for awards; and the 2006 Incentive Plan, or the Incentive Plan, which provides for a maximum of approximately 5 million shares available for awards. The 2002 Plan and 2004 Plan provide for the grant of stock options and other awards (including performance units, performance shares, share awards, restricted stock, restricted stock units, or RSUs, and stock appreciation rights, or 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, compensation committee, or employee agreement, generally all other awards will vest and all restrictions on such awards will lapse. We may, at our discretion, issue new shares or use treasury shares to satisfy vesting requirements.

Stock based compensation is measured at the grant date, based on the calculated fair value of the award and is remeasured each reporting period for liability-classified awards. Stock based compensation is recognized over the requisite employee service period (generally the vesting period of the grant). Stock based compensation is expensed or capitalized based on the nature of the employee's activities, and for the years ended December 31, 2009, 2008 and 2007 was (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Stock based compensation included in:			
General and administrative expense	$ 56,098	$ 51,262	$ 48,123
Lease operating expenses	4,392	(861)	3,896
Oil and natural gas properties under full cost method	15,930	11,465	11,010
Total stock based compensation	$ 76,420	$ 61,866	$ 63,029

Stock based compensation charged to earnings for the years ended December 31, 2009, 2008 and 2007 was (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Charged to earnings	$ 60,490	$ 50,401	$ 52,019
Tax benefit	(22,714)	(18,933)	(19,728)
	$ 37,776	$ 31,468	$ 32,291

At December 31, 2009, there was $174.6 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 4.5 years.

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. 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, 2009 and the changes during the year then ended:

	Outstanding (thousands)	Weighted Average Exercise Price	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractual Life (years)
Outstanding at January 1, 2009	2,031	$ 45.66		
Granted	842	21.18		
Exercised	(48)	16.91		
Forfeited or expired	(52)	35.81		
Outstanding at December 31, 2009	2,773	38.90	$ 5,621	2.8
Exercisable at December 31, 2009	871	43.13	$ 88	1.5

The total intrinsic value of SARs exercised during the years ended December 31, 2009, 2008 and 2007 was $0.4 million, $59.1 million and $8.3 million, respectively. The weighted average grant date fair value per share for SARs granted in 2009, 2008 and 2007 was $6.44, $13.48 and $12.42, respectively.

We estimate the fair value of SARs granted using the Black-Scholes valuation model. The following assumptions are as of December 31, 2009, 2008 and 2007:

	2009	2008	2007
Expected life (in years)	1 - 4	1 - 4	1 - 4
Volatility	41.7% - 78.1%	36.5% - 90.9%	27.6% - 30.8%
Risk-free interest rate	0.5% - 2.2%	0.4% - 1.3%	3.1% - 3.5%
Dividend yield	0%	0%	0%

The expected life represents the period of time that SARs granted are expected to be outstanding. We use historical experience with exercise and post-vesting exercise behavior to determine the expected life of the SARs granted. Expected volatility is based on the historical volatility of our common stock and other factors. 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, 2009 and the changes during the year then ended:

	Equity Instruments (thousands)	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractual Life (years)
Nonvested at January 1, 2009	5,359	$ 46.73		
Granted	1,338	22.27		
Vested	(1,072)	20.18		
Vested and deferred	(163)	18.18		
Forfeited	(18)	38.82		
Reclassified to liability instruments	(1,297)	47.45		
Nonvested at December 31, 2009	4,147	38.36	$ 114,723	2.4

	Liability Instruments (thousands)	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value ($ thousands)	Average Remaining Contractual Life (years)
Nonvested at January 1, 2009	805	$ 53.58		
Reclassified from equity instruments	1,297	47.45		
Nonvested at December 31, 2009	2,102	49.80	$ 58,138	8.2

The total intrinsic value of restricted stock and RSUs vested in 2009, 2008 and 2007 was $24.6 million, $42.7 million and $26.3 million, respectively. The intrinsic value was based upon the closing price of 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, 2008 and 2007 was $52.31 per share and $48.43 per share, respectively.

In 2006, we granted 300,000 RSUs to certain executives that will vest only upon 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 were 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 and 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, 2009, 1.2 million shares had been granted and 1.2 million shares will be granted in 2010 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 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 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 deemed granted in 2008 for accounting purposes. An executive was 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. The grant date for accounting purposes for all 1.0 million of these RSUs is March 2008.

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

Stock Options

At December 31, 2009, there were 32,823 stock options outstanding with an average exercise price of $8.93 per share and an average remaining life of 1.5 years. The intrinsic value of options exercised in the years ended December 31, 2009, 2008 and 2007 was $0.1 million, $0.5 million and $0.3 million, respectively, and we received $0.1 million, $0.3 million and $0.1 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). In 2009, 2008 and 2007 we made cash contributions totaling $9.3 million, $7.0 million and $5.5 million, respectively, to the 401(k) plan.

We have certain awards which have vested, but, at the election of the award recipients, the issuance of those common shares has been deferred. During 2009, 2008 and 2007, approximately 163,000, 123,000 and 63,000 common shares, respectively, vested and were deferred resulting in a total of approximately 380,000 deferred common shares at December 31, 2009. These common shares will be issued upon the earliest of the deferral date designated by the recipient, their retirement or death.

Note 9 — Income Taxes

For the years ended December 31, 2009, 2008 and 2007 our income tax expense (benefit) consisted of (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Current			
U.S. Federal	$ 40,548	$ 195,154	$ (2,158)
State	4,543	35,661	(2,519)
	45,091	230,815	(4,677)
Deferred			
U.S. Federal	36,530	(613,768)	110,080
State	(746)	(61,582)	4,345
	35,784	(675,350)	114,425
	$ 80,875	$ (444,535)	$ 109,748

Our deferred income tax assets and liabilities at December 31, 2009 and 2008 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, 2009	December 31, 2008
Deferred tax assets:		
Net operating loss	$ 85,070	$ 38,355
Tax credits	97,681	32,654
Commodity derivative contracts and other	47,901	49,391
	230,652	120,400
Deferred tax liabilities:		
Commodity derivative contracts	(172,376)	(551,217)
Net oil & gas acquisition, exploration and development costs and other	(1,145,497)	(599,065)
Net deferred tax liability	$ (1,087,221)	$ (1,029,882)
Current liability	$ (153,473)	$ (285,426)
Long-term liability	(933,748)	(744,456)
	$ (1,087,221)	$ (1,029,882)

Tax carryforwards at December 31, 2009, which are available for future utilization on income tax returns, are as follows (in thousands):

FEDERAL	Amount	Expiration
Alternative minimum tax (AMT) credit	$ 37,381	-
Enhanced oil recovery credit	43,917	2025
Net operating loss – regular tax	61,179	2027
STATE		
Alternative minimum tax (AMT) credit	$ 5,060	-
Enhanced oil recovery credit	22,901	2016-2020
Net operating loss – regular tax	1,202,349	2019-2024

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, 2009	2008	2007
U.S. federal income tax provision (benefit) at statutory rate	$ 76,013	$ (403,770)	$ 93,975
State income taxes, net of federal expense (benefit)	1,025	(59,516)	1,826
Non-deductible expenses	15,839	14,066	9,882
Uncertain tax positions	(18,154)	21,403	(452)
Stock based compensation	4,776	-	-
Other	1,376	(16,718)	4,517
Income tax expense (benefit) on income (loss) before income taxes	$ 80,875	$ (444,535)	$ 109,748

Tax Loss Carryovers. Certain of our U.S. tax loss carryovers obtained as a result of the acquisitions of Nuevo Energy Company, or 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. We did not record a tax benefit in either 2007 or 2008 related to non-cash employee compensation which vested in those years since we generated a net operating loss for tax purposes in 2007 and did not utilize all of this net operating loss carry forward in 2008. In 2009 we recorded tax expense of $5.1 million related to non-cash employee compensation that vested in 2009.

Unrecognized Tax Benefits. Effective January 1, 2007, we adopted the authoritative guidance for uncertainty in income taxes, which prescribed 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. In connection with this adoption, we recognized a $1.4 million cumulative effect in equity.

During 2008, we increased the balance of our net unrecognized tax benefits related to tax credits and tax deductions by $25.5 million. During 2009, we received revenue agent reports from the Internal Revenue Service, or the IRS, relating to certain of our tax years under audit. As a result of these reports, we reduced our balance of net unrecognized tax benefits and accrued interest related to tax credits and tax deductions by $28.5 million, of which $23 million positively impacted our net income in 2009 and the remainder offset a reduction in our balance of deferred tax assets related to tax credit carryforwards. We do not expect significant changes in our balance of net unrecognized tax benefits to occur within the next twelve months.

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

	2009	2008	2007
Balance at beginning of period	$ 47,163	$ 24,370	$ 19,732
Additions for tax positions in prior years	3,085	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	(33,775)	-	-
Adjustments due to any expiration of a statute of limitations	-	-	-
Balance at end of period	$ 16,473	$ 47,163	$ 24,370

Included in the balance at December 31, 2009 is approximately $15.7 million that would affect our effective tax rate if recognized.

In addition, included in the December 31, 2009 balance is an expense of approximately $0.7 million and included in the December 31, 2008 balance is a benefit of approximately $0.3 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 had approximately $2.2 million and $2.4 million of accrued interest on unrecognized tax benefits in our consolidated balance sheets as of December 31, 2009 and 2008, respectively. We did not have any accrued liabilities for penalties related to unrecognized tax benefits for the years ended December 31, 2009 and 2008.

We file income tax returns in the U.S. federal and various state and foreign jurisdictions. In 2009, the IRS completed the fieldwork related to its examination of the PXP and Nuevo U.S. income tax returns for 2003, 2004 and certain amended tax credit claims for Nuevo for the years 2000 through 2002. Revenue agent reports were issued to us by the IRS in 2009 for all of these years. With the exception of one issue related to certain deductions which is currently on administrative appeal with the IRS, we accepted the results of this examination and have reflected them in our 2009 financial statements. For the previously filed tax returns of PXP and predecessor companies, Nuevo and 3TEC Energy Corporation, we are no longer subject to U.S. federal or state income tax examinations by tax authorities for years prior to 2006 except for certain tax loss carryforwards generated before 2006 but utilized after 2005.

During 2009, the IRS completed its examination of Pogo's federal tax returns for 2006 and 2007. We accepted the results of this examination and have reflected them in our 2009 financial statements. For tax returns filed by Pogo and its subsidiary, Latigo, prior to the merger with us, we are no longer subject to U.S. federal income tax examination by the IRS except for certain tax loss carryforwards of Latigo generated in tax years prior to the merger which were utilized by us subsequent to the merger. For state tax returns filed by Pogo and Latigo prior to the merger with us, we are no longer subject to examination by state tax authorities for years prior to 2006.

Note 10 — Commitments, Contingencies and Industry Concentration

Commitments and Contingencies

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

2010	$ 17,346
2011	16,909
2012	13,085
2013	12,755
2014	10,173
Thereafter	33,226
	$ 103,494

Total expenses related to such leases were $13.0 million, $10.8 million and $7.9 million in 2009, 2008 and 2007, 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 100 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 be assured that we will be able to collect on these indemnities.

We estimate our 2010 cash expenditures related to plugging, abandonment and remediation will be approximately $7.1 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, $58 million ($114 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 $67 million). To secure its abandonment obligations, the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2009, the escrow account had a balance of $12.7 million. The fair value of our guarantee at December 31, 2009, $0.7 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. While there are signs that the economy may be improving, business conditions may remain challenging. Volatility and disruption in the financial and credit markets 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.

In the second quarter of 2009, we received a net recovery of $87.3 million as our share of the award for damages in the breach of contract lawsuit Amber Resources Company et al. v. United States.

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 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.

During 2009, 2008 and 2007, sales to ConocoPhillips accounted for approximately 44%, 36% and 45%, respectively, of our total revenues and sales to Plains Marketing, L.P., or PMLP, accounted for approximately 22%, 23% and 31%, respectively, of our total revenues. During such periods, no other purchaser accounted for more than 10% of our total revenues. As expected, the contract with PMLP expired in November 2009, and we have entered into contracts with purchasers who previously purchased through PMLP. 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 ConocoPhillips to support trade receivables. Accordingly, a material adverse change in ConocoPhillips's financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

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 us having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil and gas production which could have a negative impact on future results of operations or cash flows.

Note 11 — Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2009	2008	2007
Cash payments for interest (net of capitalized interest)	$ 45,496	$ 117,278	$ 44,193
Cash payments for income taxes	$ 151,682	$ 127,428	$ 116,545

At December 31, 2009 and 2008, accrued capital expenditures included in accounts payable in the consolidated balance sheet were $135 million and $245 million, respectively.

Common stock and treasury shares issued in connection with our compensation plans were as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Shares (1)	765	508	357
Amount (1)	$ 15,498	$ 27,512	$ 15,175

(1) The number of shares is net of shares withheld for employee taxes and the amount is based on the grant date price.

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 totaling $59.1 million. 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; and
- noncash additions to oil and gas properties of $55.3 million in 2009 and $60.5 million in 2007 and reductions to oil and gas properties of $18.7 million in 2008, respectively, related to our 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

Certain of our crude oil puts and natural gas collars included deferred premiums to be paid to the counterparty based on the settlement terms specified in the contract. During 2009, 2008, and 2007, we entered into derivative contracts with deferred premiums of $74.1 million, $313.6 million and $40.1 million, respectively.

Note 12 — Stockholders' Equity

Earnings Per Share

Weighted average shares outstanding for computing basic and diluted earnings were as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Common shares outstanding - basic	124,405	108,828	78,627
Unvested restricted stock, restricted stock units and stock options	883	-	1,181
Common shares outstanding - diluted	125,288	108,828	79,808

Included in computing basic earnings per share are certain awards which have vested, but, at the election of the award recipients, the issuance of those common shares has been deferred. In the year ended December 31, 2009 and 2007, 2.4 million and 0.1 million restricted stock units, respectively, were excluded in computing diluted earnings per share because they were antidilutive due to the impact of the unrecognized compensation cost on the calculation of assumed proceeds in the application of the treasury stock method. 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 computing earnings per share, no adjustments were made to reported net income.

Common Stock Offerings

During the second quarter of 2009, we sold 13.8 million shares of our common stock at a price of $18.70 per share to the public and received $250.9 million of net proceeds after deducting the underwriting discounts and offering expenses. We used the net proceeds for general corporate purposes, including capital expenditures.

During the third quarter of 2009, we sold 17.25 million shares of our common stock at a price of $24.00 per share to the public and received $397.1 million of net proceeds after deducting the underwriting discounts and offering expenses. We used the net proceeds for general corporate purposes, including to fund a portion of the $1.1 billion payment for the Haynesville Carry.

Authorized Shares

The number of authorized common shares at December 31, 2009 is 250 million, with a par value of $0.01.

The number of authorized preferred shares at December 31, 2009 is 5,000,000, with a par value of $0.01. No preferred shares were issued as of December 31, 2009.

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 may 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 are authorized to expend an additional $695.8 million under the program.

Note 13 — Other Operating Expense and Other Income (Expense)

Other operating expense in 2009 consists primarily of a restocking fee related to a cancelled purchase order, a valuation adjustment for materials and supplies inventory and idle drilling equipment costs resulting from unused contract commitments partially offset by a reduction in preacquisition operating expense accruals related to our acquisition of Pogo Producing Company in 2007.

Other income (expense) consists of the following (in thousands):

	December 31,		
	2009	**2008**	**2007**
Royalty receipts (1)	$ 23,501	$ -	$ -
Preacquisition adjustments (1)	3,203	(16,547)	-
Equity income in partnership	-	947	-
Other	1,264	3,025	6,322
	$ 27,968	$ (12,575)	$ 6,322

(1) Reflects preacquisition amounts for properties sold by Pogo prior to our acquisition of Pogo.

Note 14 — Consolidating Financial Statements

We are the issuer of $600 million of 7¾% Senior Notes, $565 million of 10% Senior Notes, $500 million of 7% Senior Notes, $400 million of 7⅝% Senior Notes and $400 million of 8⅝% Senior Notes as of December 31, 2009, 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");
- the Guarantor Subsidiaries on a combined basis;
- the Non-Guarantor Subsidiaries on a combined basis;
- elimination entries necessary to consolidate the Issuer, Guarantor Subsidiaries and Non-Guarantor Subsidiaries; and
- PXP on a consolidated basis.

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2009
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 1,304	$ 11	$ 544	$ -	$ 1,859
Accounts receivable and other current assets	210,625	113,320	2,820	(21,989)	304,776
	211,929	113,331	3,364	(21,989)	306,635
Property and Equipment, at cost					
Oil and natural gas properties - full cost method	4,161,478	8,104,424	57,781	-	12,323,683
Other property and equipment	49,403	35,648	40,616	-	125,667
	4,210,881	8,140,072	98,397	-	12,449,350
Less allowance for depreciation, depletion, amortization and impairment	(2,212,695)	(5,346,513)	(14)	1,942,594	(5,616,628)
	1,998,186	2,793,559	98,383	1,942,594	6,832,722
Investment in and Advances to Affiliates	4,668,480	(1,650,163)	(68,081)	(2,950,236)	-
Other Assets	55,994	539,380	-	-	595,374
	$ 6,934,589	$ 1,796,107	$ 33,666	$ (1,029,631)	$ 7,734,731
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities	$ 528,157	$ 171,529	$ 4,854	$ (21,989)	$ 682,551
Long-Term Debt	2,649,689	-	-	-	2,649,689
Other Long-Term Liabilities	207,035	62,727	-	-	269,762
Deferred Income Taxes	350,727	(151,610)	5,699	728,932	933,748
Stockholders' Equity	3,198,981	1,713,461	23,113	(1,736,574)	3,198,981
	$ 6,934,589	$ 1,796,107	$ 33,666	$ (1,029,631)	$ 7,734,731

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

	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 Affiliates	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 STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2009
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 754,840	$ 148,306	$ -	$ -	$ 903,146
Gas sales	72,787	209,191	-	-	281,978
Other operating revenues	1,128	878	-	-	2,006
	828,755	358,375	-	-	1,187,130
Costs and Expenses					
Production costs	290,808	133,159	-	-	423,967
General and administrative	102,982	40,960	644	-	144,586
Depreciation, depletion, amortization and accretion	218,771	158,059	(10)	44,760	421,580
Impairment of oil and gas properties	-	1,712,201	-	(1,712,201)	-
Legal recovery	(81,790)	(5,482)	-	-	(87,272)
Other operating expense (income)	6,307	(4,736)	565	-	2,136
	537,078	2,034,161	1,199	(1,667,441)	904,997
Income (Loss) from Operations	291,677	(1,675,786)	(1,199)	1,667,441	282,133
Other (Expense) Income					
Equity in earnings of subsidiaries	(14,038)	(1,041)	-	15,079	-
Interest expense	(18,365)	(52,589)	(2,857)	-	(73,811)
Debt extinguishment costs	(12,093)	-	-	-	(12,093)
Loss on mark-to-market derivative contracts	(7,017)	-	-	-	(7,017)
Other income (expense)	7,954	20,057	(43)	-	27,968
Income (Loss) Before Income Taxes	248,118	(1,709,359)	(4,099)	1,682,520	217,180
Income tax (expense) benefit	(111,813)	660,149	(3,056)	(626,155)	(80,875)
Net Income (Loss)	$ 136,305	$ (1,049,210)	$ (7,155)	$ 1,056,365	$ 136,305

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

	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
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
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 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 of dollars)

	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 (Expense) Income					
Equity in earnings of subsidiaries	(10,407)	(282)	-	10,689	-
Interest expense	(39,323)	(68,692)	-	39,107	(68,908)
(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 CASH FLOWS
YEAR ENDED DECEMBER 31, 2009
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 136,305	$ (1,049,210)	$ (7,155)	$ 1,056,365	$ 136,305
Items not affecting cash flows from operating activities					
Depreciation, depletion, amortization, accretion and impairment	218,771	1,870,260	(10)	(1,667,441)	421,580
Equity in earnings of subsidiaries	14,038	1,041	-	(15,079)	-
Deferred income tax (benefit) expense	(286,517)	(306,910)	3,056	626,155	35,784
Debt extinguishment costs	12,093	-	-	-	12,093
Loss on mark-to-market derivative contracts	7,017	-	-	-	7,017
Noncash compensation	49,037	11,453	-	-	60,490
Other noncash items	5,871	442	637	-	6,950
Change in assets and liabilities from operating activities					
Accounts receivable and other assets	(78,787)	54,588	(1,641)	-	(25,840)
Accounts payable and other liabilities	(11,853)	(35,007)	109	-	(46,751)
Stock appreciation rights	(355)	-	-	-	(355)
Income taxes (receivable) payable	(108,227)	-	-	-	(108,227)
Net cash (used in) provided by operating activities	(42,607)	546,657	(5,004)	-	499,046
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(671,194)	(918,108)	(39,055)	-	(1,628,357)
Acquisition of oil and gas properties	-	(1,159,939)	-	-	(1,159,939)
Derivative settlements	1,522,412	-	-	-	1,522,412
Other	(3,665)	(487)	(10,363)	-	(14,515)
Net cash provided by (used in) investing activities	847,553	(2,078,534)	(49,418)	-	(1,280,399)
CASH FLOWS FROM FINANCING ACTIVITIES					
Borrowings from revolving credit facilities	3,513,325	-	-	-	3,513,325
Repayments of revolving credit facilities	(4,588,325)	-	-	-	(4,588,325)
Proceeds from issuance of Senior Notes	916,439	-	-	-	916,439
Costs incurred in connection with financing arrangements	(19,556)	-	-	-	(19,556)
Derivative settlements	1,392	-	-	-	1,392
Issuance of common stock	648,005	-	-	-	648,005
Investment in and advances to affiliates	(1,584,341)	1,531,603	52,738	-	-
Other	57	-	-	-	57
Net cash (used in) provided by financing activities	(1,113,004)	1,531,603	52,738	-	471,337
Net decrease in cash and cash equivalents	(308,058)	(274)	(1,684)	-	(310,016)
Cash and cash equivalents, beginning of period	309,362	285	2,228	-	311,875
Cash and cash equivalents, end of period	$ 1,304	$ 11	$ 544	$ -	$ 1,859

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

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net 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
(Gain) loss on mark-to-market 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 (receivable) payable	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, net of cash acquired	-	(77,686)	-	-	(77,686)
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)
Decrease in restricted cash	-	59,092	-	-	59,092
Other	(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					
Borrowings from revolving credit facilities	14,331,046	-	-	-	14,331,046
Repayments of revolving credit facilities	(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 of dollars)

	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
Loss (gain) on mark-to-market 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 (receivable) payable	(121,222)	-	-	-	(121,222)
Net cash provided by (used in) 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)
Derivative settlements	(99,861)	-	-	-	(99,861)
Increase in restricted cash	-	(59,092)	-	-	(59,092)
Other	(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					
Borrowings from revolving credit facilities	4,745,100	-	-	-	4,745,100
Repayments of revolving credit facilities	(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)
Purchases 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

Note 15 — Quarterly Financial Data (Unaudited)

The following table shows summary financial data for 2009 and 2008 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2009					
Revenues	$ 228,512	$ 278,681	$ 312,188	$ 367,749	$ 1,187,130
(Loss) income from operations	(20,334)	126,710	74,793	100,964	282,133
Net income	5,198	43,649	39,326	48,132	136,305
Basic earnings per share	0.05	0.37	0.30	0.34	1.10
Diluted earnings per share	0.05	0.37	0.30	0.34	1.09
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)

(1) Reflects the February 2008 divestments of 50% of our working interest in the Permian and Piceance 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 Permian and Piceance Basins. Additionally at December 31, 2008, our capitalized costs of 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.

Note 16 — Oil and Natural Gas Activities

In December 2008, the SEC issued its final rule, Modernization of Oil and Gas Reporting, which is effective for reporting 2009 reserve information. In January 2010, the FASB issued its authoritative guidance on extractive activities for oil and gas to align its requirements with the SEC's final rule. We adopted the guidance as of December 31, 2009 in conjunction with our year-end reserve report as a change in accounting principle that is inseparable from a change in accounting estimate. Under the SEC's final rule, prior period reserves were not restated. The primary impacts of the SEC's final rule on our reserve estimates include:

- the use of the twelve-month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) of $61.18 per Bbl for oil and $3.87 per MMBtu for natural gas compared to the year-end reference prices (prior to adjustment for location and quality differentials) of $79.36 per Bbl for oil and $5.79 per MMBtu for natural gas;

- certain of our undeveloped locations are not scheduled to be developed within five years, which had the impact of reducing our proved undeveloped reserves by 25 MMBOE; and

- we were able to support with reasonable certainty proved undeveloped reserves for certain horizontal locations in the Haynesville Shale, more than the two parallel offsets from a proved developed well location allowed under the previous guidelines. The impact increased our proved undeveloped reserves by 11 MMBOE.

The impact of the adoption of the SEC final rule on our financial statements is not practicable to estimate due to the operational and technical challenges associated with calculating a cumulative effect of adoption by preparing reserve reports under both the old and new rules.

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 block 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,		
	2009	2008	2007
Property acquisitions costs			
Unproved properties	$ 1,121,644	$ 1,878,842	$ 1,822,312
Proved properties	5,072	267,161	3,883,607
Exploration costs	1,309,396	520,612	465,246
Development costs	272,820	576,753	357,345
	$ 2,708,932	$ 3,243,368	$ 6,528,510

Amounts presented include capitalized general and administrative expense of $67.3 million, $60.6 million and $44.6 million in 2009, 2008 and 2007, respectively, and capitalized interest expense of $113.8 million, $70.5 million and $34.6 million in 2009, 2008 and 2007, respectively. Our international exploration costs were $42.3 million, $4.5 million and $0.1 million in 2009, 2008 and 2007, respectively.

We have completed our commitments under our production sharing contract with PetroVietnam, the state oil company of Vietnam, which included the acquisition and interpretation of approximately 850 square kilometers of 3-D seismic data and the drilling of two exploratory wells, which were plugged and abandoned after encountering a minor structurally controlled hydrocarbon accumulation in one well. Our interest in Block 124 covers approximately 1,480,000 gross acres offshore central Vietnam. In the fourth quarter of 2009, we obtained 520 kilometers of 2-D seismic data and the government of Vietnam granted a one-year extension of the first phase of our production sharing contract. We continue to evaluate our plans utilizing the 3-D seismic data, the data from the two exploratory wells and the recently acquired 2-D seismic data and we expect to finalize our plans during 2010. In the event we discontinue operations, we will record a pre-tax write-down of approximately $58 million in accumulated costs in our Vietnam cost center and we would expect to record a corresponding tax deduction for any write-down.

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 and impairment (in thousands):

	December 31,	
	2009	2008
Property subject to amortization	$ 9,044,146	$ 7,106,785
Accumulated DD&A and impairment	(5,598,995)	(5,207,600)
	$ 3,445,151	$ 1,899,185

Our average DD&A rate per BOE was $12.79, $17.69 (excluding impairment charges) and $12.92 in 2009, 2008 and 2007, respectively.

At December 31, 2008, the capitalized costs of our 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 and we recorded a non-cash pre-tax impairment charge of $3.6 billion. The reduction in proved reserves in 2008 was primarily due to the significant decline 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 further reduced our realized price. 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 decline.

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):

	Year-Ended December 31,				
	Total	**2009 (1)**	**2008 (2)**	**2007**	**Prior**
United States					
Acquisition costs	$ 2,502,815	$ 1,116,925	$ 1,118,916	$ 249,285	$ 17,689
Exploration costs	573,429	284,445	216,978	11,495	60,511
Capitalized interest	145,511	107,546	28,529	6,100	3,336
International					
Acquisition costs	14,874	-	3,623	11,251	-
Exploration costs	40,494	40,494	-	-	-
Capitalized interest	2,414	1,846	458	110	-
	$ 3,279,537	$ 1,551,256	$ 1,368,504	$ 278,241	$ 81,536

(1) Includes amounts attributable to the September 2009 pre-payment of the Haynesville Carry associated with the Chesapeake acquisition. See Note 2 – Acquisitions.

(2) Includes amounts attributable to the July 2008 Chesapeake acquisition. See Note 2 – Acquisitions.

The cost of unproved oil and gas properties are excluded from amortization until the properties are evaluated. 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. Unproved properties are assessed periodically, at least annually, to determine whether impairment has occurred. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment considers the following factors, among others; intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. The transfer of costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on our drilling plans and results, geological and geophysical evaluations, the assignment of proved reserves, availability of capital, and other factors. Costs not subject to amortization consist primarily of capital costs incurred for undeveloped acreage and wells in progress pending determination, together with capitalized interest costs for these projects. Due to the nature of the reserves, the ultimate evaluation of the properties will occur over a period of several years. We expect that 63% of the costs not subject to amortization at December 31, 2009 will be transferred to the amortization base over the next five years and the remainder in the next seven to ten years.

Approximately 44% of our domestic total net undeveloped acreage is covered by leases that will expire from 2010 through 2012. 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. Approximately 66% of the total exploration costs in the United States are associated with the two wells drilled on the Friesian deepwater prospect in the Gulf of Mexico. Well results are being evaluated and early stage commercialization initiatives for Friesian production are under study; however, these costs will be excluded from amortization until it is determined whether proved reserves can be assigned to the properties.

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,		
	2009	2008	2007
Revenues from oil and gas producing activities	$ 1,187,130	$ 2,403,471	$ 1,272,840
Production costs	(426,103)	(626,428)	(413,122)
Depreciation, depletion, amortization and accretion	(405,597)	(605,440)	(306,713)
Impairment of oil and gas properties	-	(3,629,666)	-
Income tax (expense) benefit	(133,464)	923,003	(209,589)
Results of operations from producing activities (excluding general and administrative and interest costs)	$ 221,966	$ (1,535,060)	$ 343,416

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, 2009. All of our reserves were located in the United States. In 2009 our reserves were based upon reserve reports prepared by the independent petroleum engineers of Netherland, Sewell & Associates, Inc. and Ryder Scott Company L.P., or Ryder Scott. In 2008, our reserves were based upon (1) reserve reports prepared by Netherland, Sewell & Associates, Inc. and 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 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 engineer (1% of reserve volumes).

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 2009 reserve volumes are attributable to properties in California where differentials to the 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, proved developed and proved undeveloped reserves for the three years ended December 31, 2009.

	Oil (MBbl)	Gas (MMcf)	(MBOE)
2009			
Proved Reserves			
Beginning balance	177,707	686,357	292,100
Revision of previous estimates	53,113	(86,966)	38,619
Extensions, discoveries and other additions	770	338,161	57,130
Improved recovery	-	-	-
Purchase of reserves in-place	-	13,740	2,290
Sale of reserves in-place	-	-	-
Production	(17,560)	(78,184)	(30,591)
Ending balance	214,030	873,108	359,548
Proved Developed Reserves, December 31	144,839	509,121	229,693
Proved Undeveloped Reserves, December 31	69,191	363,987	129,855
2008			
Proved Reserves			
Beginning balance	436,533	1,519,976	689,862
Revision of previous estimates	(172,359)	(256,390)	(215,091)
Extensions, discoveries and other additions	5,424	218,967	41,919
Improved recovery	-	-	-
Purchase of reserves in-place	2,513	82,651	16,288
Sale of reserves in-place	(74,110)	(799,593)	(207,375)
Production	(20,294)	(79,254)	(33,503)
Ending balance	177,707	686,357	292,100
Proved Developed Reserves, December 31	123,522	515,180	209,385
Proved Undeveloped Reserves, December 31	54,185	171,177	82,715
2007			
Proved Reserves			
Beginning balance	333,217	110,922	351,704
Revision of previous estimates	40,726	310,858	92,535
Extensions, discoveries and other additions	6,074	151,346	31,298
Improved recovery	-	-	-
Purchase of reserves in-place	74,646	976,395	237,379
Sale of reserves in-place	-	-	-
Production	(18,130)	(29,545)	(23,054)
Ending balance	436,533	1,519,976	689,862
Proved Developed Reserves, December 31	227,915	757,736	354,204
Proved Undeveloped Reserves, December 31	208,618	762,240	335,658

Revisions of Previous Estimates

In 2009, we had net positive revisions of 39 MMBOE. Positive revisions of 77 MMBOE were primarily related to higher oil prices principally at our California properties. Negative revisions of 13 MMBOE mostly related to lower gas prices, primarily at our Panhandle and South Texas properties. Additionally, certain of our undeveloped locations are scheduled for development beyond five years and were excluded from our proved reserves, resulting in a negative revision of 25 MMBOE.

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 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 related to 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 revisions 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 accounted 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.

Purchases of Reserves in-Place

In 2009, we had a total of 2 MMBOE of proved reserve additions related to interests acquired in the Haynesville Shale.

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, Discoveries and Other Additions

In 2009, we had a total of 57 MMBOE of extensions and discoveries, including 53 MMBOE in the Haynesville Shale resulting from successful drilling during 2009 that extended and developed the proved acreage and 2 MMBOE of extensions and discoveries in the Gulf of Mexico, primarily attributable to continued success in the Flatrock area.

In 2008, we had a total of 42 MMBOE of extensions and discoveries, including (1) 15 MMBOE of extensions and discoveries 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.

Sales of Reserves 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.

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,		
	2009	2008	2007
Future cash inflows	$ 14,623,292	$ 9,311,501	$ 46,466,516
Future development costs	(2,371,383)	(1,704,350)	(4,919,564)
Future production expense	(6,187,933)	(4,345,314)	(14,408,460)
Future income tax expense	(1,521,281)	(772,225)	(9,096,371)
Future net cash flows	4,542,695	2,489,612	18,042,121
Discounted at 10% per year	(2,317,856)	(1,353,238)	(10,418,798)
Standardized measure of discounted future net cash flows	$ 2,224,839	$ 1,136,374	$ 7,623,323

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 for 2009 are made using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Prior year estimates were not required to be restated and reflect previously disclosed estimates using year-end prices. These prices 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, 2009 are discussed in Note 5 – Commodity Derivative Contracts. The derivative instruments we have in place are not classified as hedges for accounting purposes. The realized sale prices used in the reserve reports as of December 31, 2009, 2008 and 2007 were $54.38, $31.75 and $85.50 per barrel of oil, respectively, and $3.53, $5.50 and $6.28 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, 2009, are as follows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Balance, beginning of year	$ 1,136,374	$ 7,623,323	$ 2,510,663
Sales, net of production expenses	(761,157)	(1,760,135)	(856,670)
Net change in sales and transfer prices, net of production expenses	1,568,827	(7,161,276)	4,250,363
Extensions, discoveries and improved recovery, net of costs	87,890	389,719	348,785
Changes in estimated future development costs	(163,602)	1,013,179	(219,710)
Previously estimated development costs incurred during the year	144,017	369,693	184,268
Purchase of reserves in-place	3,198	201,771	3,856,043
Sale of reserves in-place	-	(2,503,747)	-
Revision of quantity estimates	443,344	(1,800,309)	3,435
Accretion of discount	188,134	812,356	393,743
Net change in income taxes	(422,186)	3,951,800	(2,847,597)
Balance, end of year	$ 2,224,839	$ 1,136,374	$ 7,623,323

Company Information

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Form 10-K
A copy of the Company's annual report on Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2009, is available free of charge on request to:

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PXP LISTED NYSE

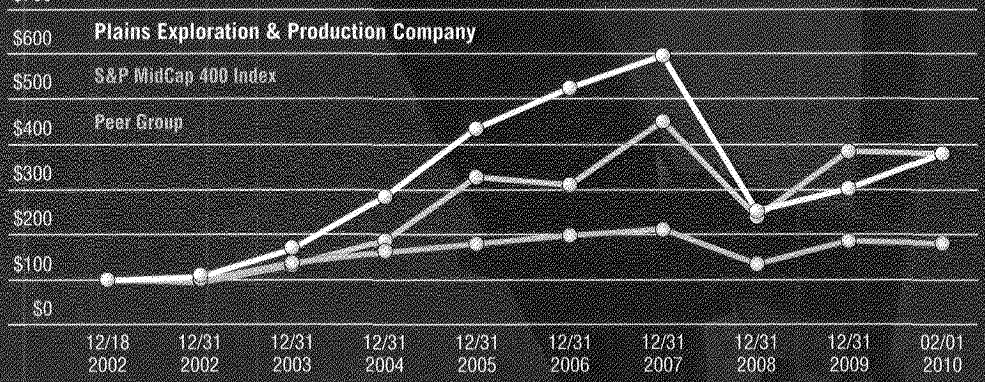
Comparison of Shareholder Return

The following graph compares the cumulative total shareholder return on our common stock with the cumulative return of (i) the S&P Mid-cap 400, and (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.

The graph covers the period from December18, 2002, through February 1, 2010, and assumes that $100 was invested on December 18, 2002 and that any dividends were reinvested. No dividends have been declared or paid on PXP's common stock. Shareholder returns over the period indicated should not be considered indicative of future shareholder returns.

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

Comparison of Cumulative Total Return



Statement Regarding Foward-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, including those related to climate change;
- 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 as required by law, 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 Estimates" 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. 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 directors, principal executive officer, principal financial officer, principal accounting officer and other executive officers) 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 or the SEC's website is incorporated by reference herein.

PXP

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