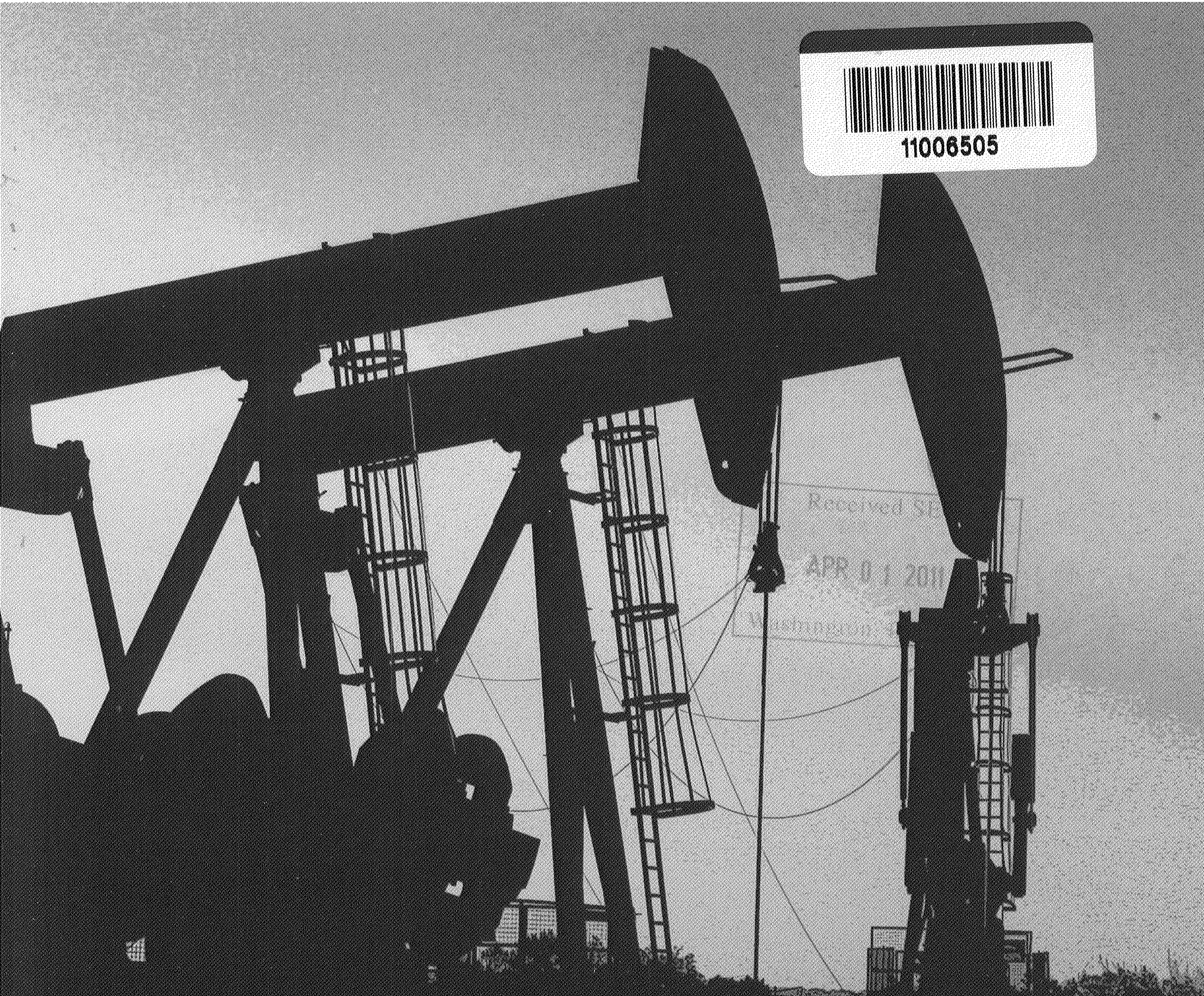


2010 ANNUAL REPORT

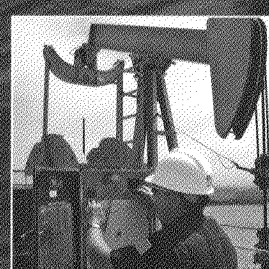
PXP

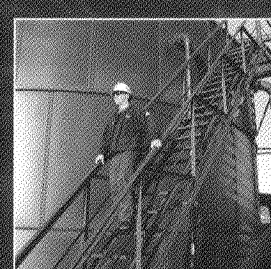
PLAINS EXPLORATION & PRODUCTION COMPANY

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





PXP is building value by finding and producing energy resources safely, reliably and efficiently.

FINANCIAL HIGHLIGHTS

(in thousands, except per share and percentage information)	2010[1]	2009	2008[2]	2007[3]	2006
Reserve Data:					
Total oil reserves (barrels)	223,268	214,030	177,707	436,533	333,217
Total gas reserves (Mcf)	1,157,070	873,108	686,357	1,519,976	110,922
Total barrels of oil equivalent (BOE)	416,113	359,548	292,100	689,862	351,704
Percentage proved developed volume	57%	64%	72%	51%	52%
Estimated future net cash flows	$6,743,128	$4,542,695	$ 2,489,612	$18,042,121	$5,652,412
Standardized measure	$3,093,135	$2,224,839	$ 1,136,374	$ 7,623,323	$2,510,663
Percentage proved developed present value	77%	80%	96%	67%	68%
Operating Data:					
Oil production (barrels)	16,769	17,560	20,294	18,124	18,975
Average oil price (per barrel)[4]	$ 68.14	$ 51.43	$ 87.05	$ 61.60	$ 55.62
Gas production (Mcf)	95,047	78,184	79,254	29,312	20,629
Average gas price (per Mcf)[4]	$ 4.29	$ 3.72	$ 8.05	$ 5.68	$ 6.73
BOE production	32,610	30,591	33,503	23,010	22,413
Average BOE price[4]	$ 47.77	$ 39.25	$ 72.03	$ 56.12	$ 53.76
Production expense per BOE	$ 14.00	$ 14.03	$ 18.91	$ 18.25	$ 14.49
Selected Financial Data:					
Total revenue	$1,544,595	$1,187,130	$ 2,403,471	$ 1,272,840	$1,018,503
Income (loss) from operations[5]	$ 358,216	$ 282,133	$(2,627,413)	$ 419,634	$1,348,450
Income (loss) before cumulative effect of accounting change	$ 103,265	$ 136,305	$ (709,094)	$ 158,751	$ 599,710
Cumulative effect of accounting change, net of income tax	–	–	–	–	$ (2,182)
Net income (loss)	$ 103,265	$ 136,305	$ (709,094)	$ 158,751	$ 597,528
Diluted income (loss) per share					
Before cumulative effect of accounting change	$ 0.73	$ 1.09	$ (6.52)	$ 1.99	$ 7.67
Cumulative effect of accounting change	–	–	–	–	$ (0.03)
Net income (loss) per share	$ 0.73	$ 1.09	$ (6.52)	$ 1.99	$ 7.64
Weighted average shares outstanding					
Basic	140,438	124,405	108,828	78,627	77,273
Diluted	141,897	125,288	108,828	79,808	78,234
Total assets	$8,894,937	$7,734,731	$ 7,111,915	$ 9,693,351	$2,463,228
Long-term debt	$3,344,717	$2,649,689	$ 2,805,000	$ 3,305,000	$ 235,500
Total stockholders' equity	$3,382,965	$3,198,981	$ 2,377,280	$ 3,338,247	$1,130,683

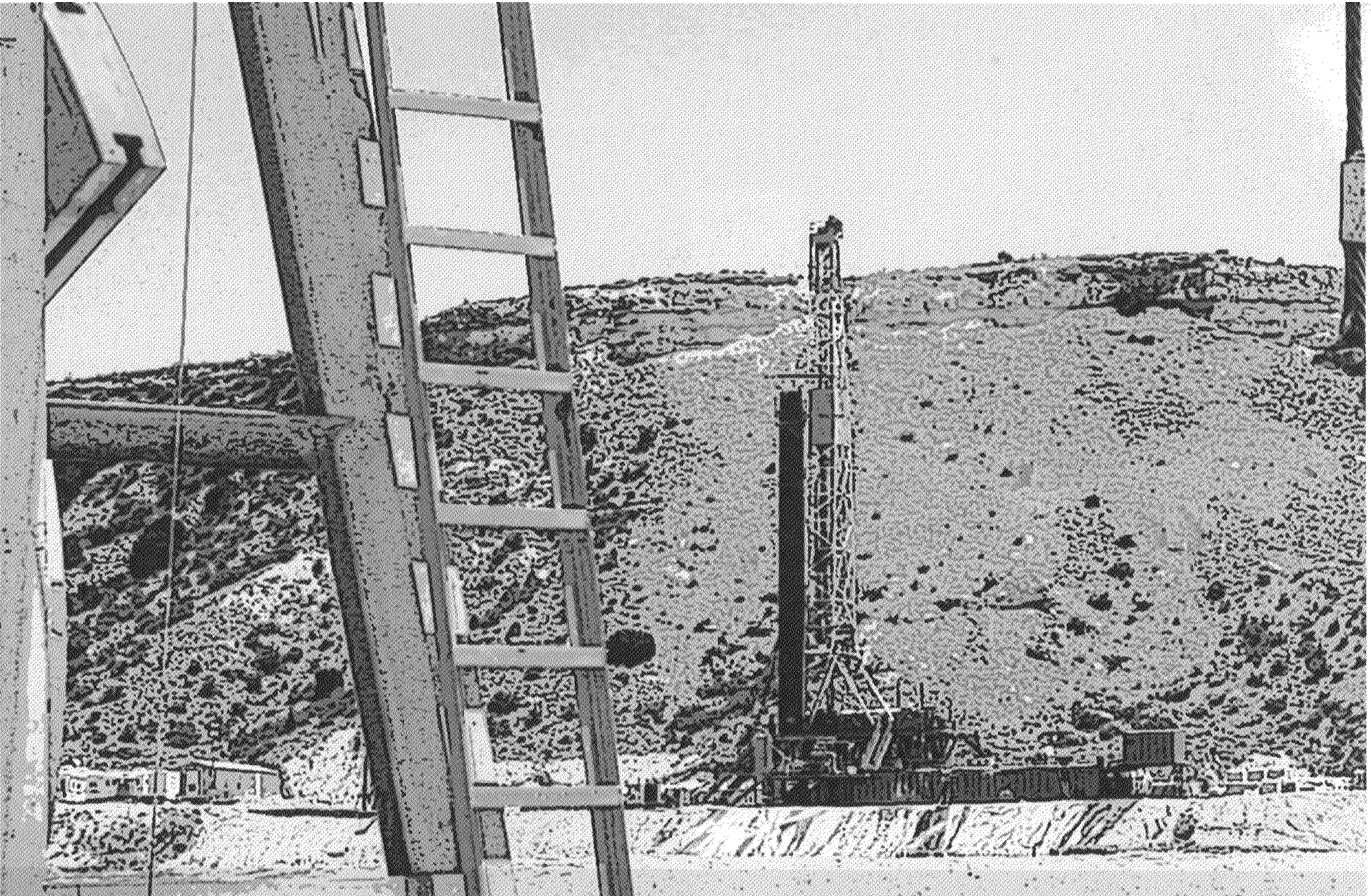
[1] Reflects the December 2010 divestiture of our interest in all of our Gulf of Mexico leasehold located in less than 500 feet of water and the acquisition of the oil and gas properties in the Eagle Ford oil and gas condensate windows in South Texas during the fourth quarter of 2010.

[2] 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.

[3] Reflects the acquisition of Pogo Producing Company effective November 6, 2007 and Piceance Basin properties effective May 31, 2007.

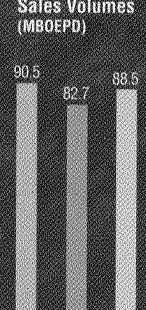
[4] Average realized sales price before derivative transactions.

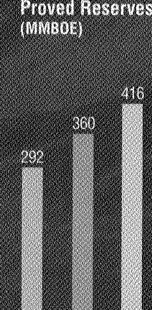
[5] We are required to perform a full cost ceiling test each quarter. At December 31, 2008, our capitalized costs of oil and gas properties exceeded the ceiling, and we recorded a pre-tax non-cash impairment of oil and gas properties of $3.6 billion.



TO OUR SHAREHOLDERS

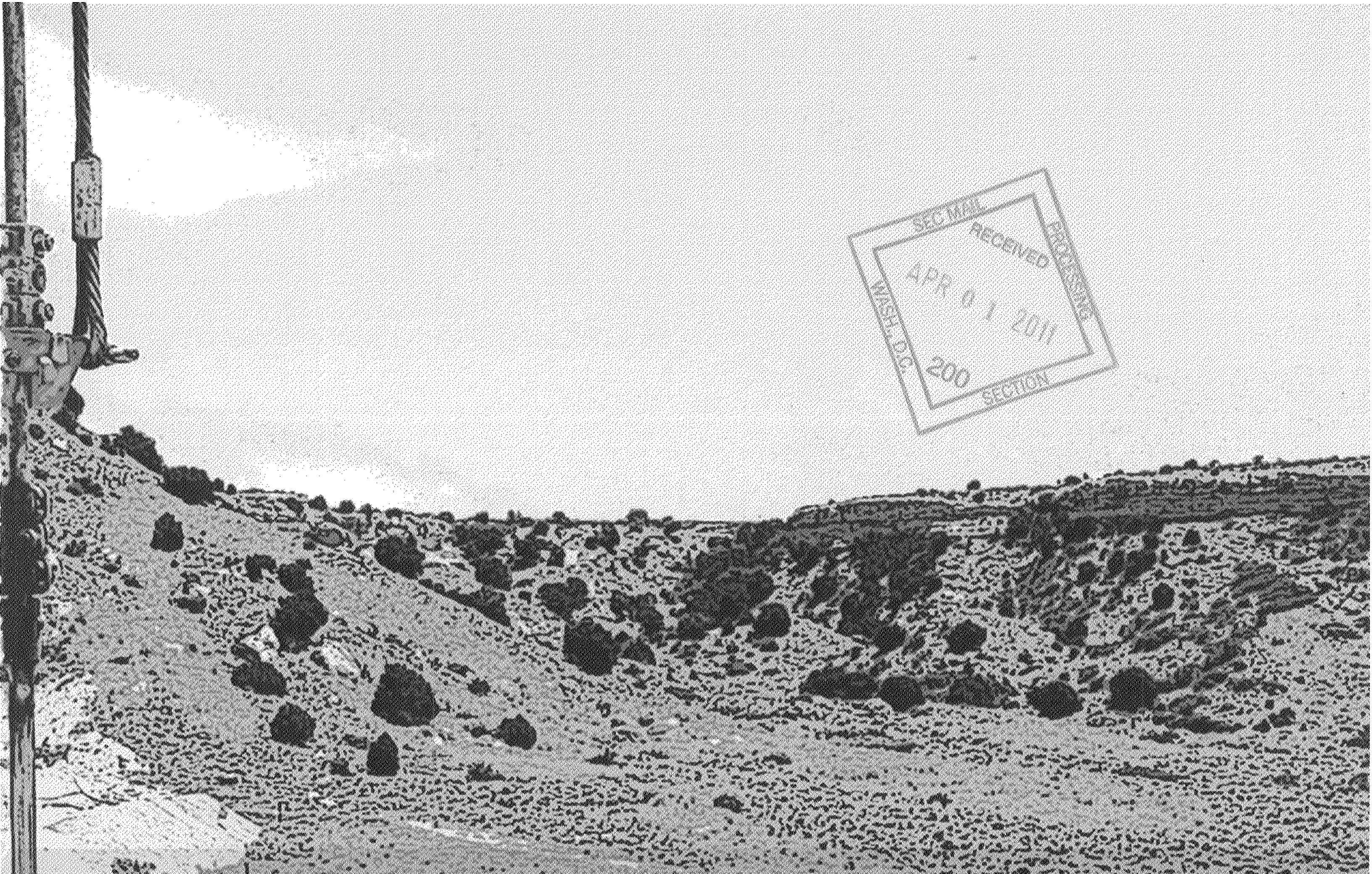
PXP completed another successful year. We navigated a challenging business environment by, once again, applying experience and innovation and remaining focused on our long-term goal of value creation. We safely grew production and reserves, strengthened our financial position, lowered portfolio geologic risk and aggressively expanded our onshore oil resource potential.





For 2010, PXP increased average daily sales volumes 7% compared to 2009 average daily sales volumes, grew proved reserves 16% over 2009 year-end amounts with finding and development costs, excluding acquisition costs, of $11.15 per barrel of oil equivalent, and received NSC Safety Leadership awards for twenty-one of our facilities. In line with our onshore oil growth strategy announced in August, we successfully acquired a significant position in the prolific South Texas Eagle Ford shale play. Next, we reduced our Gulf of Mexico long lead-time capital requirements, yet retained upside exposure to the emerging ultra-deep Wilcox exploration potential, by divesting our shelf assets in exchange for a combination of cash and a significant equity position in the well-capitalized McMoRan Exploration Co.

Activity on our remaining Gulf of Mexico assets was suspended for most of 2010 in accordance with the federal mandate following the British Petroleum Macondo incident. As we begin 2011, the regulatory environment looks just as challenging as our industry and federal government work to find common ground on further development of this most important oil producing region of the United States of America.

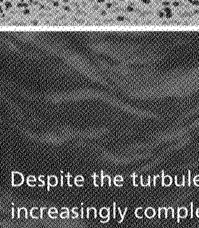


During 2010, PXP was focused on the multi-year development of its California, Louisiana, and Texas Panhandle assets and on executing the long-term operational plan geared toward expanding its oil growth strategy by entering the Eagle Ford shale play. By year-end our stock price return was 16%, outperforming the Dow Jones Industrial Average, the S&P 500, and the S&P E&P indices for the year.

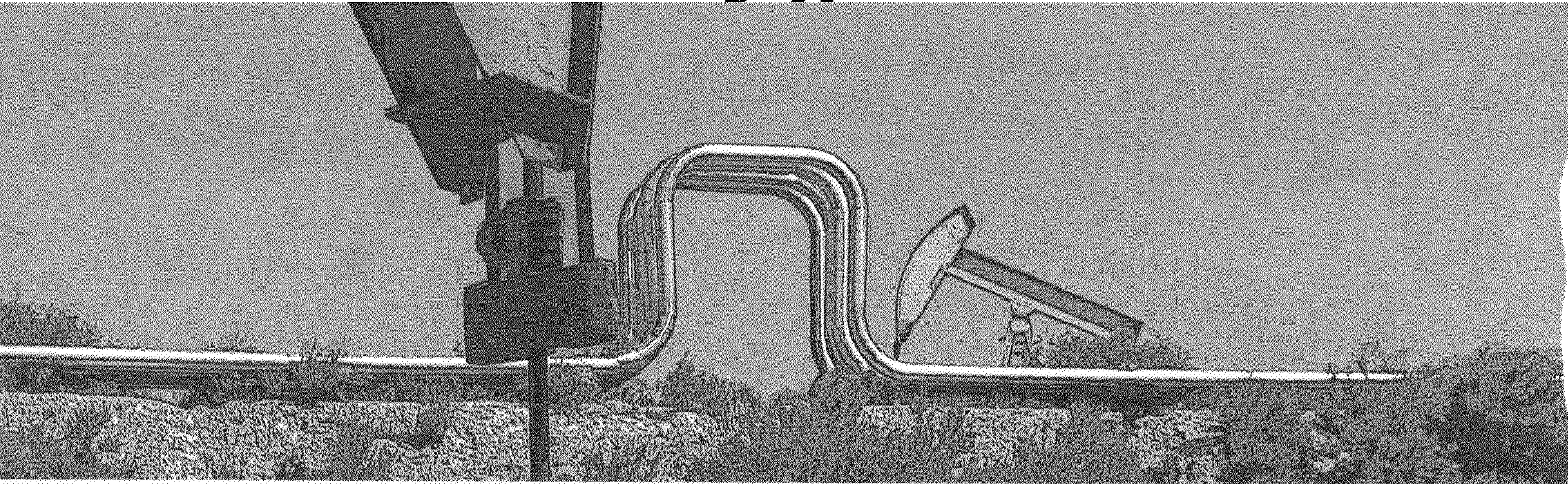
With continued crude oil price strength, countered by slowly improving economic sentiment and persistently, low natural gas prices, we remain mindful of the importance to stay balanced between oil and natural gas, to protect our balance sheet and to continuously improve operating efficiencies. For 2010, we maintained our production costs relative to 2009 on a per unit basis and opportunistically entered into 2011 and 2012 crude oil and natural gas derivatives to protect the Company's future cash flows. We ended the year with no near-term debt maturities and approximately $779 million available under our senior revolving credit facility.

Despite the turbulence in the commodity markets and an increasingly complex regulatory environment during 2010, our teams executed and produced solid operational and financial results. As we move into 2011, our balanced, low-risk portfolio of assets, our increased exposure to onshore oil-liquids development in which PXP will primarily operate, and our ongoing hedging program will serve us well in the volatile commodity price environment and allow future potential upside. These attributes, combined with our financial position, flexible capital program, and skilled and dedicated workforce, are the catalysts positioning our multi-year double-digit production and reserve growth program.

On behalf of the Board of Directors and the employees of PXP, I want to thank all of our shareholders and partners for your continued confidence and support.



James C. Flores
Chairman, President and
Chief Executive Officer

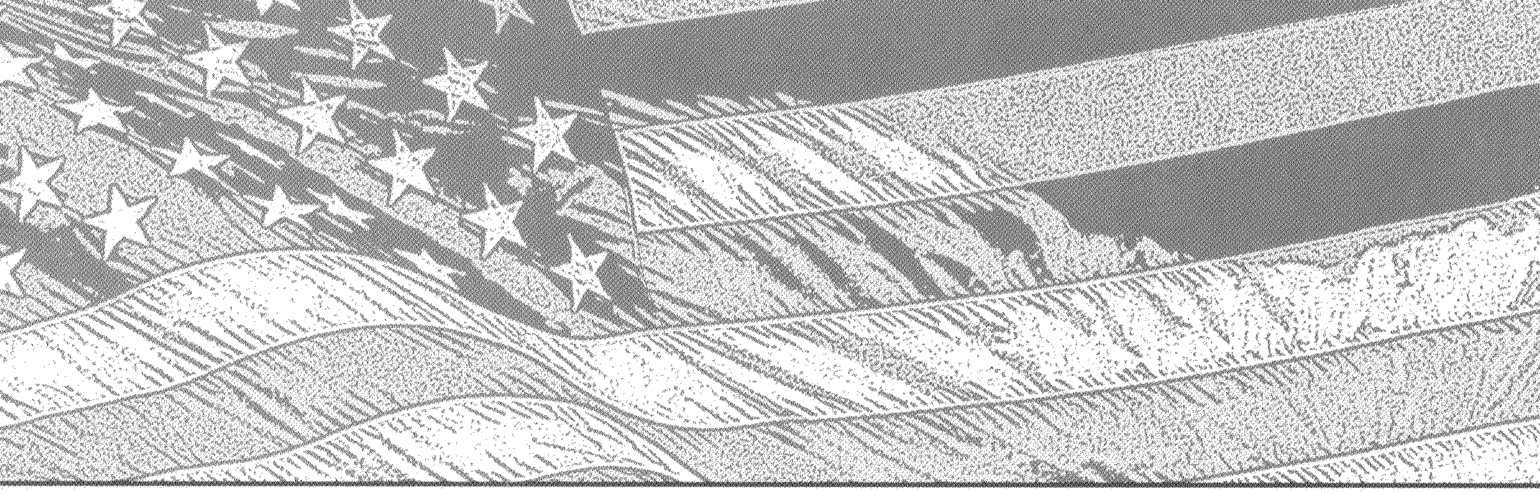


CORE ASSET AREAS

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 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.

We believe our balanced portfolio of assets, 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 California, Haynesville Shale, Eagle Ford Shale and Granite/Atoka Wash resource plays.



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, 2010

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 $2.8 billion on June 30, 2010 (based on $20.61 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date). On January 31, 2011, there were 140.1 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 2011 Annual Meeting of Stockholders.

PLAINS EXPLORATION & PRODUCTION COMPANY
2010 ANNUAL REPORT ON FORM 10-K
Table of Contents

STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking information regarding Plains Exploration & Production Company ("PXP", the "Company", "us", "our" or "we") 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;
- the effects of future laws and governmental regulation that result from the Macondo accident and oil spill in the Gulf of Mexico;
- the value of the common stock of McMoRan Exploration Co. and our ability to dispose of those shares;
- the value and completion of our Gulf of Mexico deepwater divestment;
- 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 in this Annual Report.

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 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.

PART I

Items 1 and 2. *Business and Properties*

General

Plains Exploration & Production Company, a Delaware corporation formed in 2002, 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 located in the United States. We own oil and gas properties with principal operations in:

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

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities, as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets 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 California, Haynesville Shale, Eagle Ford Shale and Granite/Atoka Wash resource plays.

Oil and Gas Reserves

As of December 31, 2010, we had estimated proved reserves of 416.1 million barrels of oil equivalent, of which 54% was comprised of oil and 57% was proved developed. We have a total proved reserve life of approximately 13 years and a proved developed reserve life of approximately seven 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, 2010, 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 $3.1 billion.

In December 2009, we adopted the SEC's final rule, Modernization of Oil and Gas Reporting, which was first effective for reporting 2009 reserve information and revised oil and gas reserve estimation and disclosure requirements. We are required to use the twelve-month average of the first-day-of-the-month reference prices compared to the year-end reference prices used in 2008 and prior years, in each case adjusted for location and quality differentials, when estimating reserve quantities.

The following table sets forth certain information with respect to our reserves that for 2010 are based upon (1) reserve reports prepared by the independent petroleum engineers of Netherland, Sewell & Associates, Inc., or NSA, and Ryder Scott Company L.P., or Ryder Scott (99% of reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum engineer (1% of reserve volumes). In 2009, our reserves were based upon reserve reports prepared by NSA and Ryder Scott. In 2008, our reserves were based upon (1) reserve reports prepared by NSA 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). The reserve volumes and values were determined using the methods prescribed by the SEC, which for 2010 and 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,		
	2010	**2009**	**2008**
Oil and Gas Reserves			
Consolidated entities			
Oil (MBbls)			
Proved developed	150,492	144,839	123,522
Proved undeveloped	72,776	69,191	54,185
	223,268	214,030	177,707
Gas (MMcf)			
Proved developed	517,183	509,121	515,180
Proved undeveloped	639,887	363,987	171,177
	1,157,070	873,108	686,357
MBOE	416,113	359,548	292,100
Entity's share of equity investee [1]			
Oil (MBbls)			
Proved developed	4,315		
Proved undeveloped	401		
	4,716		
Gas (MMcf)			
Proved developed	46,974		
Proved undeveloped	15,394		
	62,368		
MBOE	15,111		
Standardized Measure (in thousands)			
Consolidated entities [2]	$ 3,093,135	$ 2,224,839	$ 1,136,374
Entity's share of equity investee [1]	$ 210,898		

Table continued on following page.

	As of December 31,		
	2010	2009	2008
Average Realized Price (3)			
Oil (per Bbl)	$ 72.83	$ 54.38	$ 31.75
Gas (per Mcf)	$ 4.29	$ 3.53	$ 5.50
Reference Price (4)			
WTI Oil (per Bbl)	$ 79.43	$ 61.18	$ 44.60
Henry Hub Gas (per MMbtu)	$ 4.38	$ 3.87	$ 5.71
Reserve Life (years)	13.0	11.2	9.9

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010.

(2) Our year-end 2010 standardized measure includes future development costs related to proved undeveloped reserves of $437 million, $356 million, and $472 million in 2011, 2012 and 2013, respectively.

(3) 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 2010 and 2009 and year-end prices for 2008, 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.

(4) Reflects the twelve-month average of the first-day-of-the-month reference prices for 2010 and 2009 and the year-end reference prices for 2008. Our reference prices are the West Texas Intermediate spot price for oil and the Henry Hub spot price for gas.

In 2010, we had a total of 77 MMBOE of extensions and discoveries, including 54 MMBOE in the Haynesville Shale resulting from successful drilling during 2010 that extended and developed our proved acreage and 17 MMBOE in the Panhandle resulting from successful horizontal development of the Granite/Atoka Wash. Positive revisions of 20 MMBOE primarily related to higher realized oil and gas prices and proved reserve additions in the Eagle Ford Shale were 1 MMBOE. The divestment of our Gulf of Mexico shallow water shelf properties resulted in a 9 MMBOE reduction.

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.

During the three-year period ended December 31, 2010, we participated in 559 exploratory wells, of which 540 were successful, including 488 successful Haynesville Shale wells, and 444 development wells, of which 441 were successful. During this period, we incurred aggregate oil and gas acquisition, exploration and development costs of $7.7 billion, approximately 67% of which was for acquisition and development activities. During this period, proved reserve additions from acquisitions, extensions and discoveries totaled 196 MMBOE.

All of our proved undeveloped reserves are scheduled for development within five years. As of December 31, 2010, we had proved undeveloped reserves of 179 MMBOE, an increase of 49 MMBOE relative to December 31, 2009. Significant additions to proved undeveloped reserves resulted primarily from continued successful development of the Haynesville Shale as well as successful horizontal development of the Granite/Atoka Wash in the Panhandle. During 2010, we invested $168 million and converted 13 MMBOE, or 10% of our year-end 2009 proved undeveloped reserve balance, to proved developed. The pace of development was heavily influenced by the large number of unproved locations that were drilled on our Haynesville Shale acreage in order to capture our significant leasehold on a held by production basis. We project this leasehold to be essentially all held by production by early 2012, at which point the conversion percentage is projected to increase significantly.

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 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. 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, 2010 and 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. The prices for oil and gas have historically 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 21 and 34 years of industry experience, between 11 and 34 years of reservoir engineering/management experience, and between five and nine 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 NSA 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 NSA 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.

Eagle Ford

During the fourth quarter of 2010, we completed the acquisition of approximately 60,000 net acres in the Eagle Ford oil and gas condensate windows in South Texas for approximately $596.3 million in cash. We funded the acquisition primarily with borrowings under our senior revolving credit facility.

In conjunction with the acquisition of the Eagle Ford properties, and in anticipation of divesting our deepwater Gulf of Mexico properties, we entered into a series of reverse like-kind exchange agreements pursuant to Section 1031 of the Internal Revenue Code, or IRC. The purchase consideration related to the Eagle Ford properties was loaned by PXP to the qualified intermediary, PXP Operations LLC, to facilitate the potential tax deferred reverse like-kind exchange treatment under IRC 1031.

Chesapeake Participation Agreement

In July 2008, we acquired from a subsidiary of Chesapeake Energy Corporation a 20% interest in Chesapeake's Haynesville Shale leasehold for approximately $1.65 billion in cash, funded 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.

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 issuance of $400 million of 8⅝% Senior Notes due 2019, cash on hand and borrowings under 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. As a result of the prepayment of the Haynesville Carry, we do not pay promoted well costs for costs attributable to periods subsequent to the third quarter of 2009. During 2010 and 2009, we spent $16 million and $59 million, respectively, to acquire approximately 1,200 and 5,000 net additional acres in the Haynesville Shale. At December 31, 2010 we had approximately 105,000 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 Divestments. The effective date of the transaction was January 1, 2008.

Piceance Basin Properties

In June 2008, PXP and a subsidiary of Occidental Petroleum Corporation, or Oxy, acquired equal shares of working interests in acreage in the Piceance Basin in Colorado adjacent to the Piceance Basin properties we acquired in May 2007. 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 December 2008, we sold our interest in these acres to Oxy. See Divestments. Oxy assumed our obligation for the unpaid consideration in connection with the sale.

Divestments

In December 2010, we completed the divestment of our Gulf of Mexico shallow water shelf properties to McMoRan. At closing and after preliminary closing adjustments, we received approximately $86.1 million in cash, which included $11.1 million in working capital adjustments, and 51.0 million shares of McMoRan common stock in exchange for all our interests in our Gulf of Mexico leasehold located in less than 500 feet of water. The transaction was completed pursuant to an Agreement and Plan of Merger dated as of September 19, 2010, and effective as of August 1, 2010, between us and certain of our subsidiaries and McMoRan and certain of its subsidiaries. The McMoRan shares were valued at approximately $665.9 million based on McMoRan's closing stock price of $17.18 on December 30, 2010 discounted to reflect certain restrictions on the marketability of the McMoRan shares under the registration rights agreement and stockholder agreement entered into by us and McMoRan at the closing of the transaction. The cash proceeds received, net of approximately $8.8 million in transaction costs, were primarily used to repay outstanding borrowings under our credit facilities. The proceeds were recorded as reductions to capitalized costs pursuant to full cost accounting rules.

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 these properties in the Pogo Producing Company acquisition in November 2007. We also sold 50% of our working interests in oil and gas properties located in the Mesaverde geologic section of the Piceance Basin in Colorado, including a 50% interest in the entity that held our 25% interest in the associated midstream assets, Collbran Valley Gas Gathering, LLC, or CVGG. We acquired these properties in May 2007. 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. 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 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.

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 onshore Gulf Coast Region and Mid-Continent Region. 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, 2010, our additions to proved reserves from extensions and discoveries totaled 176 MMBOE. During this period we incurred aggregate oil and gas development and exploration costs of $3.8 billion.

Our 2011 capital budget is approximately $1.2 billion, including capitalized interest and general and administrative expenses, and is focused on our major development and exploration areas. Our resources will be primarily directed to Haynesville Shale, Granite Wash and Eagle Ford Shale resource plays, along with continued development activities in California. 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 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.

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 California and the Gulf Coast Region as well as continued exploration primarily in the Gulf Coast Region and Mid-Continent Region. Capital additions to our oil and gas properties, excluding acquisitions, were $1.1 billion in 2010.

The following table sets forth information with respect to our proved oil and gas reserves as of December 31, 2010:

	Proved Reserves as of December 31, 2010		
	Proved Developed	**Proved Undeveloped**	**Total Proved**
		(MMBOE)	
Consolidated entities			
Onshore California	134.1	64.1	198.2
Offshore California	12.4	-	12.4
Gulf Coast Region	48.0	86.3	134.3
Mid-Continent Region	16.9	29.0	45.9
Rocky Mountains	25.3	-	25.3
Total	236.7	179.4	416.1
Entity's share of equity investee (1)	12.1	3.0	15.1

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010.

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 2010, we spent $47 million on capital projects in the LA Basin, focused on improved waterflood recovery efficiency through infill drilling, producer and injector well recompletions and facility additions and enhancements to process higher fluid volumes. Our net average daily LA Basin sales volumes were 11.5 MBOE per day in the fourth quarter of 2010. In 2011, we will continue 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 $76 million in 2010 on capital projects in the San Joaquin Basin focused on improved recovery efficiency through infill drilling, well recompletions, facility expansions and enhancements to reduce air emissions in all of our primary fields. Our net average daily San Joaquin Basin sales volumes were 18.9 MBOE per day in the fourth quarter of 2010.

We continue to evaluate our exposure to the previously announced positive industry discoveries in Kern County, California. We hold approximately 16,000 net acres in the Kern County area. In 2011, we will continue to concentrate on development drilling and on recompletion projects and facility expansions in the San Joaquin Basin. Additionally, we are participating in the acquisition of 3-D seismic over a significant portion of our acreage and are developing a diatomite expansion project.

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 2010, we spent $3 million on capital projects in this field focused on improved recovery efficiency primarily through facility enhancements and recompletion projects. Our net average daily sales volumes from the Arroyo Grande Field were 1.0 MBOE per day in the fourth quarter of 2010.

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. In 2010 we began construction of key water handling components and in 2011 we expect to begin construction on the facility.

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 2010 were 3.5 MBOE per day. Much of our planned activity on this property in 2011 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 2010, we spent $18 million on capital projects primarily associated with equipment improvements. Our combined net average daily sales volumes from our Pt. Pedernales and Lompoc Fields averaged 5.1 MBOE per day in the fourth quarter of 2010. During 2011, we plan to perform a significant platform upgrade associated with capacity expansion to accommodate the drilling of additional extended reach Monterey wells in this area.

Gulf Coast Region

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, 2010, we have rights to approximately 578,000 gross acres (105,000 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 2010 were 146.3 MMcfe per day, a 65% increase from the 88.8 MMcfe per day net average during the first quarter of 2010. Sales volumes are expected to continue to increase to approximately 160 MMcfe net per day by year-end 2011. During 2011, Chesapeake is expected to operate an average of approximately 25 rigs and other operators are expected to operate 15 or more rigs on our acreage.

We spent $336 million of capital in 2010 focused on converting undeveloped leases to leases held by production. For 2011, we allocated approximately $200 million of our capital budget to Haynesville activity and plan to continue to focus on the development of our undeveloped leasehold with the anticipation that virtually all of our leasehold will be held by production by early 2012.

Eagle Ford Shale

During the fourth quarter of 2010, we completed the acquisition of approximately 60,000 net acres in the Eagle Ford oil and gas condensate windows in South Texas for approximately $596.3 million. At December 31, 2010, four rigs were operating, seven gross wells have been drilled since acquisition and 16 wells were in progress on the properties.

At December 31, 2010, we own interests in oil and gas properties on approximately 95,000 gross acres (60,000 net acres) with 159 square miles of 3-D seismic data located in the Eagle Ford Shale. Based on the 80 to 130 acre well spacing, we anticipate that there could be approximately 500 potential net well locations. During 2011, we plan to have four to six rigs drilling horizontal development wells on our acreage.

South Texas

We own interests in oil and gas properties on approximately 85,000 gross acres (54,000 net acres) with 321 square miles of 3-D seismic data located in Texas. 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 2010, we spent $21 million on exploration and development projects in this area primarily associated with drilling activities and we drilled eight gross wells. Our net average daily sales volumes from these properties were 7.9 MBOE per day for the fourth quarter of 2010. In 2011, we plan to continue focusing on development in these fields.

East Texas

We hold approximately 37,000 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.

Mid-Continent Region

We have interests in oil and gas properties on approximately 371,500 gross leasehold acres with 834 square miles of 3-D seismic located in Texas and Oklahoma. Development activities are concentrated in the Wheeler and Marvin Lake areas in Wheeler and Hemphill Counties in Texas. The structural and stratigraphic objectives include Cleveland Sands, Mississippian carbonates, and Granite/ Atoka Wash found at varying depths.

We spent $145 million on exploration and development projects in 2010, including drilling in the Wheeler and Marvin Lake areas as well as exploration drilling at Courson Ranch. Our net average daily sales volumes from our Mid-Continent Region properties were 8.1 MBOE per day in the fourth quarter of 2010.

We hold leases covering 11,000 gross and approximately 6,500 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/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 15,000 gross and 13,200 net acres. During 2010, we drilled 20 horizontal wells from our currently identified inventory of approximately 150 horizontal well locations targeting discrete intervals within the Granite/Atoka Wash section. As of December 31, 2010, we had five rigs drilling horizontal wells and 14 wells in progress. 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 2011, we plan to continue our five rig 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 approximately 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 64,000 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.

During 2010, we spent $3 million on capital projects in the Madden Deep Unit. Our net average daily sales volumes were 3.9 MBOE per day for the fourth quarter of 2010 due to the Lost Cabin Gas Plant operating below full capacity. The Madden Deep Unit experienced a significant amount of downtime during 2010 for repair work following a fire in a portion of the Lost Cabin Gas Plant. Repair work was completed during the fourth quarter of 2010. Production is expected to reach full capacity during the first quarter of 2011.

In 2011, we are focused on maintaining production and high-grading the remaining development drilling inventory.

Big Horn Basin

We hold leases covering 54,000 gross and net acres in the Big Horn Basin located in Wyoming. We spudded a well in late 2010, which is in progress at year-end, with the objective of evaluating the Mowry Oil Shale potential for our acreage. We plan to drill and test two horizontal Mowry Shale wells during 2011.

Deepwater Gulf of Mexico

Our deepwater Gulf of Mexico portfolio is anchored by Friesian and Lucius, two high-quality oil discoveries, and a comprehensive exploration portfolio with interests in 107 blocks, nine well-defined prospects and an additional 22 prospects or leads in Pliocene, Miocene and lower Tertiary reservoirs.

In April 2010, the Deepwater Horizon drilling rig, which was engaged in deepwater Gulf of Mexico drilling operations for another operator, sank after an explosion and fire. In response to this event and the resulting oil spill, certain federal agencies and governmental officials ordered a six month moratorium on the drilling of new deepwater wells and a suspension of permitted wells being drilled in the deepwater Gulf of Mexico. The moratorium was conditionally lifted in October 2010.

In response to market conditions related to the Gulf of Mexico drilling moratorium in 2010 and as part of our ongoing portfolio optimization, we engaged Barclays Capital and Jefferies & Company to assist us in evaluating various alternatives with respect to our Gulf of Mexico operations. In September 2010, we announced that the data room process for the planned Gulf of Mexico deepwater divestment is underway. The transaction is expected to close in the first half of 2011.

Vietnam

During the second quarter of 2010, we completed our interpretation of seismic and drilling data from our two offshore Vietnam exploratory wells and decided not to pursue additional exploratory activities in this area. We have submitted a notice to the Vietnam state oil company in order to terminate our production sharing contract in accordance with its terms. The costs related to our Vietnam oil and gas properties not subject to amortization were transferred to our Vietnam full cost pool where they were subject to the ceiling limitation. Because our Vietnam full cost pool had no associated proved oil and gas reserves, we recorded a non-cash pre-tax impairment charge of $59.5 million. We also recorded a corresponding tax benefit of $23.0 million.

Acquisition, Exploration and Development Expenditures

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

	Year Ended December 31,		
	2010 (1)	2009	2008
Consolidated entities			
Property acquisition costs			
Unproved properties	$ 612,471	$ 1,121,644	$ 1,878,842
Proved properties	48,078	5,072	267,161
Exploration costs	719,004	1,309,396	520,612
Development costs	363,242	272,820	576,753
	$ 1,742,795	$ 2,708,932	$ 3,243,368

(1) We completed the divestment of our Gulf of Mexico shallow water properties on December 30, 2010. Our proportionate share of McMoRan's 2010 costs incurred is not presented because it is insignificant as PXP owned the investment for one day and it is not practicable to determine one day of costs incurred.

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, 2010, 2009 and 2008.

	Inglewood (1)	Haynesville Shale (1)	Other	Total
2010				
Oil and liquids sales (MBbls)	2,211	-	14,558	16,769
Gas (MMcf)				
Production	1,089	43,051	50,907	95,047
Used as fuel	31	-	1,923	1,954
Sales	1,058	43,051	48,984	93,093
MBOE				
Production	2,393	7,175	23,042	32,610
Sales	2,387	7,175	22,723	32,285
Average realized sales price before derivative transactions (2)				
Oil (per Bbl)	$ 73.02	$ -	$ 67.41	$ 68.14
Gas (per Mcf)	4.45	4.17	4.39	4.29
Per BOE	69.60	25.05	52.66	47.77
Average production cost per BOE (3)				
Lease operating expenses	$ 17.88	$ 1.61	$ 9.17	$ 8.13
Steam gas costs	-	-	2.92	2.06
Electricity	5.98	-	1.26	1.33
Gathering and transportation	0.22	4.54	0.77	1.57

Table continued on following page.

	Inglewood (1)	Haynesville Shale (1)	Other	Total
2009				
Oil and liquids 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
MBOE				
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 liquids 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
MBOE				
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

(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. The markets for oil and gas have historically 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 risk on sales of oil and gas production. 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 and collar contracts and natural gas put option and collar contracts entered into with financial institutions.

A substantial portion of our oil reserves are located in California and approximately 60% 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 2010, we received approximately 89% of the NYMEX index price for crude oil sold under the ConocoPhillips contract, which represented approximately 51% of our total crude oil production.

Approximately 22% of our 2010 crude oil production is sold under contracts that provide for NYMEX less a fixed price differential (as of December 31, 2010 the fixed price differential averaged $6.43 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 49% 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 2010, 2009 and 2008, sales to ConocoPhillips accounted for 57%, 44% and 36%, respectively, of our total revenues. During 2009 and 2008, sales to Plains Marketing, L.P., or PMLP, accounted for 22% and 23%, respectively, of our total revenues. The contract with PMLP expired in November 2009, and we entered into contracts with purchasers who previously purchased through PMLP, the most significant of which was ConocoPhillips. During 2010, 2009 and 2008 no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect; however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, 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.

Acreage

The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2010:

	Developed Acres		Undeveloped Acres (1)	
	Gross	Net	Gross	Net
California				
Onshore	59,466	58,889	51,240	35,370
Offshore	43,335	39,062	-	-
Louisiana				
Onshore	193,261	35,819	295,160	51,513
Offshore	-	-	589,547	202,967
Oklahoma	19,243	5,860	2,304	570
Texas	334,234	158,426	276,042	192,963
Utah	-	-	65,871	33,719
Wyoming	66,135	8,927	137,307	125,362
Other states (2)	11,933	8,102	12,759	7,638
	727,607	315,085	1,430,230	650,102

(1) Approximately 41% of our total net undeveloped acres is covered by leases that expire from 2011 through 2013. In 2008 and 2010, we added a significant number of new leases in the Haynesville Shale and the Eagle Ford Shale, respectively, with lease terms generally ranging from two to three years; however, we are actively participating in the drilling of wells in these areas 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.

Productive Wells

As of December 31, 2010, we had working interests in 2,969 gross (2,857 net) active producing oil wells and 1,849 gross (829 net) active producing gas wells. One or more completions in the same well bore are counted as one well. If any well in which one of the multiple completions is an oil completion, then the well is classified as an oil well. As of December 31, 2010, we owned interests in seven gross wells containing multiple completions.

Drilling Activities

The number of oil and gas wells completed during the years ended December 31, 2010, 2009 and 2008 is set forth below:

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells (1)						
Oil	6.0	3.1	1.0	1.0	7.0	2.7
Gas	318.0	38.3	156.0	19.6	52.0	18.1
Dry	4.0	2.2	10.0	6.6	5.0	3.6
	328.0	43.6	167.0	27.2	64.0	24.4
Development Wells						
Oil	109.0	106.4	16.0	12.7	125.0	90.2
Gas	8.0	2.7	24.0	12.4	159.0	80.0
Dry	1.0	1.0	1.0	0.2	1.0	1.0
	118.0	110.1	41.0	25.3	285.0	171.2
	446.0	153.7	208.0	52.5	349.0	195.6

(1) Includes extension wells.

At December 31, 2010, there were 258 gross exploratory and 22 gross development wells (32.1 net exploratory and 17.8 net development wells) in progress including 244 wells in the Haynesville Shale area where we had approximately 50 rigs actively drilling horizontal wells at year-end. We had 30 wells in progress in the Eagle Ford Shale and the Panhandle Granite/Atoka Wash where we had nine rigs actively drilling horizontal wells at year-end.

Investment

At December 31, 2010, we owned 51.0 million shares of McMoRan common stock or an approximate 32.4% of their common shares outstanding. McMoRan is a publicly-traded oil and gas exploration and production company (New York Stock Exchange listing MMR) engaged in the exploration, development and production of natural gas and oil in the United States, specifically offshore in the shallow waters of the Gulf of Mexico Shelf and onshore in the Gulf Coast area. We acquired the McMoRan common stock and other consideration in exchange for all of our interests in our Gulf of Mexico leasehold located in less than 500 feet of water. See Items 1 and 2 – Business and Properties – Divestments.

As contemplated by the Agreement and Plan of Merger, we and McMoRan entered into a registration rights agreement and a stockholder agreement at the closing of the transaction. Under the terms of the registration rights agreement, McMoRan is obligated to file a registration statement covering the McMoRan shares within 60 days after closing. The registration rights agreement also gives us piggyback registration rights and demand registration rights under certain circumstances. Under the terms of the stockholder agreement, McMoRan has expanded its board of directors and we have the right to designate two board members for so long as we own at least 10% of the outstanding shares of McMoRan. If our ownership falls below 10%, but is at least 5%, we will have the right to designate one director. The stockholder agreement requires us to refrain from certain activities that could be undertaken to acquire control of McMoRan and from transferring any McMoRan shares for one year after closing (subject to certain exceptions). After one year, we may sell shares of McMoRan common stock pursuant to underwritten offerings, in periodic sales under a shelf registration statement to be filed by McMoRan (subject to certain volume limitations), pursuant to the exercise of piggyback registration rights or as otherwise permitted by applicable law.

Real Estate

We have surface development activities on 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.

During 2010, we primarily focused our efforts at the Montebello properties. 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 ten miles east of downtown Los Angeles. We are actively pursuing the entitlement process for our Montebello properties. 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 2010, we spent approximately $6 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.

BOEMRE. The United States Bureau of Ocean Energy Management, Regulation and Enforcement, or BOEMRE, an agency of the Department of Interior and previously known as the Minerals Management Service, 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 BOEMRE has promulgated regulations and issued a Series of "Notices to Lessees" 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 BOEMRE 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 BOEMRE 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 Department of the Interior's Office of Natural Resources Revenue 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 BOEMRE or successor agency because of staffing, economic, environmental or other reasons (or other actions taken by the BOEMRE or its successors under its regulatory authority) could adversely affect our operations.

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, the regulation of the spacing, plugging and abandonment of wells and the regulation of injection of fluids including steam and natural gas. 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, and agencies' increasingly stricter interpretation of them, 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. Periodically, additional taxes are proposed. The City of Los Angeles and the City of Beverly Hills each have production tax initiatives proposed on their March 2011 ballot.

Pipeline Regulation. We have pipelines to deliver our production to sales points. Some of 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 authority, FERC 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. 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 effect 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.

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. 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, 2011, we had 826 full-time employees, three of whom were employed in our international operations and 325 of whom were field personnel involved in oil and gas producing activities. We believe our relationship with our employees is good.

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.

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, 2010 and 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 2010 and 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.

Oil and natural gas prices have the potential to be volatile. 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 could lose all or part of our investment in McMoRan common stock.

We owned approximately 32.4% of the outstanding shares of common stock of McMoRan as of December 31, 2010. Under the terms of the stockholder agreement with McMoRan, we are generally prohibited from transferring any of our shares of McMoRan common stock prior to December 30, 2011. Thereafter, we may sell shares of McMoRan common stock pursuant to underwritten offerings, in periodic sales under a shelf registration statement to be filed by McMoRan (subject to certain volume limitations), pursuant to the exercise of piggyback registration rights or as otherwise permitted by applicable law. Our ability to sell shares of McMoRan common stock could be severely limited, both as to timing and amount, and as a result of factors beyond our control. In addition, the market price of shares of McMoRan common stock that we hold may decline substantially before we sell them.

We do not control McMoRan's assets and operations and the value of our investment in McMoRan's common stock is subject to all of the risks and uncertainties inherent in McMoRan's business, which include, but are not limited to, the following:

- general economic and business conditions;
- variations in the market demand for, and prices of, oil and natural gas;
- drilling results;
- unanticipated fluctuations in flow rates of producing wells due to mechanical or operational issues (including those experienced by wells operated by third parties where McMoRan is a participant);

- oil and natural gas reserve expectations;
- the potential adoption of new governmental regulations;
- the failure of third party partners to fulfill their commitments;
- the ability to hold current or future lease acreage rights;
- the ability to satisfy future cash obligations and environmental costs;
- adverse conditions, such as high temperatures and pressure that could lead to mechanical failures or increased costs;
- access to capital to fund drilling activities;
- other general exploration and development risks and hazards inherent in the production of oil and natural gas;
- tropical storms, hurricanes and other adverse weather conditions, which are common in the Gulf of Mexico during certain times of the year;
- the exercise of preferential rights by third parties; and
- other factors discussed in McMoRan's Annual Report on Form 10-K and as are included from time to time in McMoRan's public announcements and other filings with the SEC.

For the reasons described above, we may not realize an adequate return on our investment and we may incur losses on sales of our investment. We have elected to measure our equity investment in McMoRan at fair value. As a result, unrealized gains and losses on the investment will be reported in our consolidated statement of income, which could result in volatility in our earnings. If we are required to write down the value of our investment, it could reduce our net income or result in losses. The value of our investment in shares of McMoRan common stock is subjective. Declines in the valuation of our investment may result in other than temporary impairments of this asset, which would lead to accounting charges that could have a material adverse effect on our net income and results of operations.

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 – Commodity Price 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.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or Dodd-Frank Act. The Dodd-Frank Act creates a new regulatory framework for oversight of derivatives transactions by the Commodity Futures Trading Commission, or CFTC, and the SEC. Among other things, the Dodd-Frank Act subjects certain swap participants to new capital, margin and business conduct standards. In addition, the Dodd-Frank Act contemplates that where appropriate in light of outstanding exposures, trading liquidity and other factors, swaps (broadly defined to include most hedging instruments other than futures) will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. While we may qualify for one or more of such exceptions, the scope of these exceptions is uncertain and will be further defined through rulemaking proceedings at the CFTC and SEC in the coming months. Further, although we may qualify for exceptions, our derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the new legislation, which may increase our transaction costs or make it more difficult for us to enter into hedging transactions on favorable terms. Our inability to enter into hedging transactions on favorable terms, or at all, could increase our operating expenses and put us at increased exposure to the risk of adverse changes in oil and natural gas prices, which could adversely affect the predictability of cash flows from sales of oil and natural gas.

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

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

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

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.

Our operations in the Gulf of Mexico and offshore California could be adversely impacted by the Macondo accident and resulting oil spill.

The six-month moratorium on the drilling of new deepwater wells and a suspension of permitted wells currently being drilled in the Outer Continental Shelf regions of the Gulf of Mexico and Pacific Ocean was conditionally lifted in October 2010. Notwithstanding the lifting of the moratorium on October 12, 2010, we cannot predict with certainty when new permits will be granted under the new requirements.

We have offshore exploration, development and production ongoing in the Gulf of Mexico and California. The BOEMRE is expected to issue additional governmental regulation of the offshore exploration and production industry. Recent legislative proposals include limitations upon, or elimination of, existing liability caps, an increased minimum level of financial responsibility and additional safety and spill-response requirements. We cannot predict with any certainty what form the additional regulation or limitations will take. The impact upon our business of such regulations or limitations could include cost increases, offshore exploration and development activity delay, as well as changes in the availability and cost of insurance.

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 operations are susceptible to hurricanes. Any of these operating hazards could cause serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages, or property damage, all of which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development and acquisition, or could result in a loss of our properties.

Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. As a result, we do not believe that insurance coverage for the full potential liability, especially environmental liability, is currently available at reasonable cost. In addition, we are self-insured for named windstorms in the Gulf of Mexico. 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.

There is potential for 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. Deterioration in the financial 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 21 lenders. At December 31, 2010, 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 demand. 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 us 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.

Our asset carrying values may be impaired in 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; 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 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". For 2010, the twelve-month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) were $79.43 per Bbl for oil and $4.38 per MMBtu for natural gas. At December 31, 2010, the ceiling with respect to our domestic oil and gas properties exceeded the net capitalized costs of those properties by approximately 16%. During the second quarter of 2010, we transferred costs related to our Vietnam oil and gas properties not subject to amortization to our Vietnam full cost pool, which has no associated proved oil and gas reserves. We recorded a non-cash pre-tax impairment charge of $59.5 million and a corresponding tax benefit of $23.0 million.

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.

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 BOEMRE 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 on 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 SDWA 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 and the Eagle Ford 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 is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2010, we had leases on approximately 105,000 net acres in the Haynesville Shale area and approximately 60,000 net acres in the Eagle Ford 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 Haynesville Shale acreage and portions of the Eagle Ford Shale acreage, we have limited impact upon the drilling schedule for those leases.

Increased drilling in the Haynesville Shale and the Eagle Ford 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 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, 2010, goodwill totaled $535 million and represented approximately 6% 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. 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.

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 the Obama Administration's Fiscal Year 2012 budget proposal, released by the Office of Management and Budget on February 14, 2011, is the elimination or deferral of certain key U.S. federal income tax deductions and credits currently available to oil and gas exploration companies. Such changes include, but are not limited to, (i) the elimination of current deductions for intangible drilling and development costs; (ii) the elimination of the deduction for certain U.S. production activities for oil and gas properties; (iii) an extension of the amortization period for certain geological and geophysical expenditures and (iv) the repeal of the enhanced oil recovery credit. Some of these same proposals to repeal or limit oil and gas tax deductions and credits are included in other legislation that is currently before Congress. It is unclear 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, or the passage of bills that are currently before Congress which contain similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions and credits that are currently available with respect to oil and gas exploration and development and could negatively affect our financial results.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially and adversely affect our financial condition and results of operations.

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. *Reserved*

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
2010		
1st Quarter	$36.60	$28.09
2nd Quarter	35.21	19.28
3rd Quarter	27.34	19.54
4th Quarter	32.75	25.63
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

At January 31, 2011, we had approximately 2,372 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 sheet at December 31, 2010 and 2009 and the related consolidated statements of income and cash flows for each of the three years in the period ended December 31, 2010 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,				
	2010 (1)	2009	2008 (2)	2007 (3)	2006
	(In thousands, except per share amounts)				
Income Statement Data					
Revenues	$1,544,595	$1,187,130	$2,403,471	$1,272,840	$1,018,503
Costs and Expenses					
Production costs	451,902	423,967	626,428	413,122	313,125
General and administrative	136,437	144,586	153,306	124,006	123,134
Depreciation, depletion, amortization and accretion	551,118	421,580	621,484	316,078	216,782
Impairment of oil and gas properties (4)	59,475	-	3,629,666	-	-
Gain on sale of oil and gas properties (5)	-	-	-	-	(982,988)
Legal recovery	(8,423)	(87,272)	-	-	-
Other operating (income) expense	(4,130)	2,136	-	-	-
	1,186,379	904,997	5,030,884	853,206	(329,947)
Income (Loss) from Operations	358,216	282,133	(2,627,413)	419,634	1,348,450
Other Income (Expense)					
Gain on sale of assets (6)	-	-	65,689	-	-
Interest expense	(106,713)	(73,811)	(116,991)	(68,908)	(64,675)
Debt extinguishment costs	(1,189)	(12,093)	(18,256)	-	(45,063)
(Loss) gain on mark-to-market derivative contracts (7)	(60,695)	(7,017)	1,555,917	(88,549)	(297,503)
Gain on termination of merger agreement (8)	-	-	-	-	37,902
Other income (expense)	14,391	27,968	(12,575)	6,322	5,496
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	204,010	217,180	(1,153,629)	268,499	984,607
Income tax benefit (expense)					
Current	93,090	(45,091)	(230,815)	4,677	(142,378)
Deferred	(193,835)	(35,784)	675,350	(114,425)	(242,519)
Income (Loss) Before Cumulative Effect of Accounting Change	103,265	136,305	(709,094)	158,751	599,710
Cumulative effect of accounting change, net of tax expense (9)	-	-	-	-	(2,182)
Net Income (Loss)	$ 103,265	$ 136,305	$ (709,094)	$ 158,751	$ 597,528
Earnings (Loss) Per Share					
Basic					
Income (loss) before cumulative effect of accounting change	$ 0.74	$ 1.10	$ (6.52)	$ 2.02	$ 7.76
Cumulative effect of accounting change	-	-	-	-	(0.03)
Net income (loss)	$ 0.74	$ 1.10	$ (6.52)	$ 2.02	$ 7.73
Diluted					
Income (loss) before cumulative effect of accounting change	$ 0.73	$ 1.09	$ (6.52)	$ 1.99	$ 7.67
Cumulative effect of accounting change	-	-	-	-	(0.03)
Net income (loss)	$ 0.73	$ 1.09	$ (6.52)	$ 1.99	$ 7.64
Weighted Average Common Shares Outstanding					
Basic	140,438	124,405	108,828	78,627	77,273
Diluted	141,897	125,288	108,828	79,808	78,234

Table continued on following page.

	Year Ended December 31,				
	2010 (1)	2009	2008 (2)	2007 (3)	2006
			(In thousands)		
Cash Flow Data					
Net cash provided by operating activities	$ 912,470	$ 499,046	$ 1,371,409	$ 588,112	$ 674,981
Net cash (used in) provided by investing activities	(1,575,308)	(1,280,399)	(227,790)	(2,243,137)	811,999
Net cash provided by (used in) financing activities	667,413	471,337	(857,190)	1,679,572	(1,487,633)

	As of December 31,				
	2010 (1)	2009	2008 (2)	2007 (3)	2006
			(In thousands)		
Balance Sheet Data					
Assets					
Cash and cash equivalents	$ 6,434	$ 1,859	$ 311,875	$ 25,446	$ 899
Other current assets	396,453	304,776	1,164,566	649,474	183,897
Property and equipment, net	7,220,752	6,832,722	4,513,396	8,377,227	2,107,524
Goodwill	535,144	535,237	535,265	536,822	158,515
Investment (10)	664,346	-	-	-	-
Other assets	71,808	60,137	586,813	104,382	12,393
	$ 8,894,937	$ 7,734,731	$ 7,111,915	$ 9,693,351	$ 2,463,228
Liabilities and Stockholders' Equity					
Current liabilities	$ 533,689	$ 682,551	$ 993,645	$ 818,046	$ 460,192
Long-term debt	3,344,717	2,649,689	2,805,000	3,305,000	235,500
Other long-term liabilities	278,516	269,762	191,534	272,627	170,574
Deferred income taxes	1,355,050	933,748	744,456	1,959,431	466,279
Stockholders' equity	3,382,965	3,198,981	2,377,280	3,338,247	1,130,683
	$ 8,894,937	$ 7,734,731	$ 7,111,915	$ 9,693,351	$ 2,463,228

(1) Reflects the December 2010 divestiture of our interest in all of our Gulf of Mexico leasehold located in less than 500 feet of water and the acquisition of the oil and gas properties in the Eagle Ford oil and gas condensate windows in South Texas during the fourth quarter of 2010.
(2) 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.
(3) Reflects the acquisition of Pogo, effective November 6, 2007 and the Piceance Basin properties effective May 31, 2007.
(4) During 2010, the costs related to our Vietnam oil and gas properties not subject to amortization were transferred to our Vietnam full cost pool where they were subject to the ceiling limitation. Because our Vietnam full cost pool had no associated proved oil and gas reserves, we recorded a non-cash pre-tax impairment charge of $59.5 million. 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.
(5) Represents gain on the sale of oil and gas properties to subsidiaries of Oxy of $345 million and gain on the sale of non-producing oil and gas properties to Statoil of $638 million. Gain on the sale of these oil and gas properties was recognized because the sale caused a significant change in the relationship between capitalized costs and proved reserves.
(6) Represents the gain on the sale of our investment in CVGG.
(7) 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.
(8) Represents the fee received by us, net of expense, in connection with a terminated merger in 2006.
(9) Cumulative effect of adopting the authoritative guidance for stock-based compensation.
(10) Our investment is measured at fair value with gains and losses recognized on the income statement.

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

Plains Exploration & Production Company, a Delaware corporation formed in 2002, 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 located in the United States. We own oil and gas properties with principal operations in:

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

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities, as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets 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 California, Haynesville Shale, Eagle Ford Shale and Granite/Atoka Wash resource plays. As of December 31, 2010, we had estimated proved reserves of 416.1 MMBOE, of which 54% was comprised of oil and 57% 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 – Commodity Price Risk.

Recent Developments

In response to market conditions related to the Gulf of Mexico drilling moratorium in 2010 and as part of our ongoing portfolio optimization, we began the process of divesting our Gulf of Mexico properties and acquiring additional onshore properties. In December 2010, we completed the divestment of our Gulf of Mexico shallow water shelf properties to McMoRan. At closing and after preliminary closing adjustments, we received approximately $86.1 million in cash, which included $11.1 million in working capital adjustments, and 51.0 million shares of McMoRan common stock, in exchange for all our interests in our Gulf of Mexico leasehold located in less than 500 feet of water. The transaction was completed pursuant to an Agreement and Plan of Merger dated as of September 19, 2010, and effective as of August 1, 2010, between us and certain of our subsidiaries and McMoRan and certain of its subsidiaries. The McMoRan shares were valued at approximately $665.9 million based on McMoRan's closing stock price of $17.18 on December 30, 2010 discounted to reflect certain restrictions on the marketability of the McMoRan shares under the registration rights agreement and stockholder agreement entered into by us and McMoRan at the closing of the transaction. The proceeds were recorded as reductions to capitalized costs pursuant to full cost accounting rules.

In September 2010, we announced that the data room process for the planned Gulf of Mexico deepwater divestment is underway. The transaction is expected to close in the first half of 2011.

During the fourth quarter of 2010, we completed the acquisition of approximately 60,000 net acres in the Eagle Ford oil and gas condensate windows in South Texas for approximately $596.3 million in cash. We funded the Eagle Ford acquisition primarily with borrowings under our senior revolving credit facility.

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. The markets for oil and gas have historically been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas and our levels of production are subject to wide fluctuations and depend on numerous factors beyond our control, including supply and demand, economic conditions, foreign imports, the actions of OPEC, political conditions in other oil-producing countries, and governmental regulation, legislation and policies. Under the SEC's full cost accounting rules, we review the carrying value of our proved oil and gas properties each quarter. These rules generally require that we price our future oil and gas production at the 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. Prior to the fourth quarter of 2009, 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. These 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. At December 31, 2010, the ceiling with respect to our oil and gas properties exceeded the net capitalized costs of those properties by approximately 16%. During the second quarter of 2010, we transferred costs related to our Vietnam oil and gas properties not subject to amortization to our Vietnam full cost pool, which has no associated proved oil and gas reserves. We recorded a non-cash pre-tax impairment charge of $59.5 million and a corresponding tax benefit of $23.0 million.

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, gathering and transportation costs and other costs necessary to operate our producing properties. Depreciation, depletion and amortization, or DD&A, for producing oil and gas properties is calculated using the units of production method based upon estimated proved reserves. For the purposes of computing DD&A, 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.

We have elected to measure our equity investment in McMoRan at fair value. As a result, unrealized gains and losses on the investment will be reported in our consolidated statement of income, and could result in volatility in our earnings. See Item 7A – Quantitative and Qualitative Disclosures About Market Risk – Equity Price Risk.

Results Overview

For the year ended December 31, 2010, we reported net income of $103.3 million, on total revenues of $1.5 billion. This compares to net income of $136.3 million on total revenues of $1.2 billion for the year ended December 31, 2009, and a net loss of $709.1 million on total revenues of $2.4 billion for the year ended December 31, 2008. 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 and the divestiture of the remaining 50% of our interest in the Permian and Piceance Basins effective December 1, 2008.

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,		
	2010	2009	2008
Sales Volumes			
Oil and liquids sales (MBbls)	16,769	17,560	20,294
Gas (MMcf)			
Production	95,047	78,184	79,254
Used as fuel	1,954	2,358	2,223
Sales	93,093	75,826	77,031
MBOE			
Production	32,610	30,591	33,503
Sales	32,285	30,198	33,133
Daily Average Volumes			
Oil and liquids sales (Bbls)	45,943	48,110	55,449
Gas (Mcf)			
Production	260,402	214,203	216,540
Used as fuel	5,353	6,461	6,073
Sales	255,049	207,742	210,467
BOE			
Production	89,343	83,811	91,539
Sales	88,451	82,734	90,527
Unit Economics (in dollars)			
Average NYMEX Prices			
Oil	$ 79.61	$ 62.09	$ 99.75
Gas	4.38	3.97	9.06
Average Realized Sales Price			
Before Derivative Transactions			
Oil (per Bbl)	$ 68.14	$ 51.43	$ 87.05
Gas (per Mcf)	4.29	3.72	8.05
Per BOE	47.77	39.25	72.03
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 8.13	$ 8.31	$ 9.88
Steam gas costs	2.06	1.78	3.96
Electricity	1.33	1.45	1.59
Production and ad valorem taxes	0.91	1.28	2.84
Gathering and transportation	1.57	1.21	0.64
DD&A (oil and gas properties)	15.87	12.79	17.69

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

	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Oil derivatives			
Settlements	$ (67,917)	$ 141,297	$ (81,447)
Monetization of crude oil puts and swaps	-	1,074,361	-
Natural gas derivatives	37,996	308,146	47,163
	$ (29,921)	$ 1,523,804	$ (34,284)

Comparison of Year Ended December 31, 2010 to Year Ended December 31, 2009

Oil and gas revenues. Oil and gas revenues increased $0.3 billion, to $1.5 billion for 2010 from $1.2 billion for 2009 primarily due to an $8.52 per BOE increase in average realized prices and a 7% increase in sales volumes. Increased production from our Haynesville Shale properties is primarily responsible for the increase in sales volumes.

Oil revenues increased $239.6 million to $1.1 billion for 2010 from $903.1 million in 2009 reflecting higher average realized prices ($293.5 million) partially offset by lower sales volumes ($53.9 million). Our average realized price for oil increased $16.71 to $68.14 per Bbl for 2010 from $51.43 per Bbl for 2009. The increase is primarily attributable to an increase in the NYMEX oil price, which averaged $79.61 per Bbl in 2010 versus $62.09 per Bbl in 2009. Oil sales volumes decreased 2.2 MBbls per day to 45.9 MBbls per day in 2010 from 48.1 MBbls per day in 2009, primarily reflecting decreased production from our California properties.

Gas revenues increased $117.6 million to $399.6 million in 2010 from $282.0 million in 2009 due to an increase in sales volumes ($74.1 million) and an increase in realized prices ($43.5 million). Gas sales volumes increased from 207.7 MMcf per day in 2009 to 255.0 MMcf per day in 2010 primarily reflecting increased production from our Haynesville Shale properties partially offset by decreased production from our South Texas and Gulf Coast asset areas. Our average realized price for gas was $4.29 per Mcf in 2010 compared to $3.72 per Mcf in 2009. Our realized price for gas increased primarily due to an increase in the NYMEX price for natural gas ($4.38 per Mcf in 2010 versus $3.97 per Mcf in 2009).

Lease operating expenses. Lease operating expenses increased $11.6 million, to $262.5 million in 2010 from $250.9 million in 2009, reflecting higher costs primarily due to an increased number of producing wells in the Haynesville Shale and higher expenditures for well workovers primarily from our California properties. On a per unit basis, lease operating costs decreased to $8.13 per BOE in 2010 versus $8.31 per BOE in 2009.

Steam gas costs. Steam gas costs increased $12.6 million, to $66.4 million in 2010 from $53.8 million in 2009, primarily reflecting higher cost of gas used in steam generation. In 2010, we burned approximately 15.7 Bcf of natural gas at a cost of approximately $4.23 per MMBtu compared to 15.1 Bcf at a cost of approximately $3.57 per MMBtu in 2009.

Electricity. Electricity decreased $1.1 million, to $42.8 million in 2010 from $43.9 million in 2009, primarily reflecting a decrease in rates in California. On a per unit basis, electricity was $1.33 per BOE in 2010 and $1.45 per BOE in 2009.

Production and ad valorem taxes. Production and ad valorem taxes decreased $9.3 million, to $29.4 million in 2010 from $38.7 million in 2009 primarily reflecting lower ad valorem taxes and production tax abatements. The reduction in ad valorem taxes reflects lower commodity prices at the time of assessment. The valuation of our oil and gas properties and related ad valorem taxes has a direct relationship to commodity price movements, and will increase as prices increase.

Gathering and transportation expenses. Gathering and transportation expenses increased $14.0 million, to $50.7 million in 2010 from $36.7 million in 2009, primarily reflecting an increase in production from our Haynesville Shale properties, partially offset by a decrease in rates and volumes at our Gulf of Mexico properties prior to the December 2010 sale.

General and administrative expense. G&A expense decreased $8.2 million, to $136.4 million in 2010 from $144.6 million in 2009 primarily due to a decrease in stock-based compensation expense.

Depreciation, depletion and amortization. DD&A expense increased $126.2 million, to $533.4 million in 2010 from $407.2 million in 2009. The increase was attributable to our oil and gas depletion, primarily due to a higher per unit rate ($94.1 million) and increased production ($32.0 million). Our oil and gas unit of production rate increased to $15.87 per BOE in 2010 compared to $12.79 per BOE in 2009. Our oil and gas DD&A rate for 2011, after the effect of our fourth quarter 2010 acquisitions and divestments, is expected to be $16.28 per BOE.

Impairment of oil and gas properties. During the second quarter of 2010, we completed our interpretation of seismic and drilling data from our two offshore Vietnam exploratory wells and decided not to pursue additional exploratory activities in this area. The costs related to our Vietnam oil and gas properties not subject to amortization were transferred to our Vietnam full cost pool where they were subject to the ceiling limitation. Because our Vietnam full cost pool had no associated proved oil and gas reserves, we recorded a non-cash pre-tax impairment charge of $59.5 million. At December 31, 2010, the ceiling with respect to our domestic oil and gas properties exceeded the net capitalized costs and we did not record an impairment.

Legal recovery. We received a net recovery of $8.4 million in 2010 and $87.3 million in 2009 as our share of a portion of the judgments in the Amber Resources Company et al. v. United States related lawsuits.

Interest expense. Interest expense increased $32.9 million, to $106.7 million in 2010 from $73.8 million in 2009, primarily due to greater average debt outstanding attributed to the Senior Notes issued in March 2010 and increased borrowings under our senior revolving credit facility related to the purchase of our Eagle Ford Shale properties during the fourth quarter 2010. Interest expense is net of capitalized interest on oil and natural gas properties not subject to amortization but in the process of development. We capitalized $130.9 million and $116.2 million of interest in 2010 and 2009, respectively.

Debt extinguishment costs. In connection with reductions of the borrowing base on our senior revolving credit facility, we recorded $1.2 million and $12.1 million of debt extinguishment costs in 2010 and 2009, respectively.

(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 in our 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 $60.7 million loss on mark-to-market derivative contracts in 2010, which was primarily associated with a decrease in the fair value of our 2011 and 2012 crude oil and natural gas contracts due to higher forward commodity prices partially offset by a gain on our 2010 natural gas collars. We recognized a $7.0 million loss on mark-to-market derivative contracts in 2009, 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 commodity prices.

Other income (expense). Other income for 2010 primarily consisted of interest on royalty refunds related to production in prior years. Other income for 2009 primarily consisted of net royalty refunds related to properties sold by Pogo prior to our acquisition.

Income tax benefit (expense). Our 2010 income tax expense was $100.7 million, reflecting an annual effective tax rate of 49%, as compared with an income tax expense of $80.9 million and an effective tax rate of 37% for 2009. Variances in our annual effective tax rate from the 35% federal statutory rate for these years resulted primarily from the tax effects of permanent differences including expenses that are not deductible because of IRS limitations, the special deduction related to domestic production, state income taxes, foreign operations, tax and financial reporting differences related to non-cash compensation and changes to our balance of unrecognized tax positions.

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 2008 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 2008 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 ongoing cost savings program. 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 our 2008 divestments.

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 our ongoing cost savings program, partially offset by higher stock-based compensation expense.

Depreciation, depletion and amortization. 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 is net of capitalized interest on oil and natural gas properties not subject to amortization but in the process of development. We capitalized $116.2 million and $71.8 million of interest in 2009 and 2008, respectively.

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

(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 for 2009 primarily consisted of net royalty refunds related to properties sold by Pogo prior to our acquisition. Other expense for 2008 primarily consisted of pre-acquisition gas imbalance expenses related to our Pogo acquisition.

Income tax benefit (expense). 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 resulted from the tax effects of permanent differences including expenses that are not deductible because of IRS limitations, the special deduction related to domestic production, state income taxes, tax and financial reporting differences related to non-cash employee compensation and changes to our balance of unrecognized tax positions.

Liquidity and Capital Resources

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. These situations 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. Volatility and disruption in the financial and credit markets 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. In August 2010, we entered in an Amended and Restated Credit Agreement which increased our borrowing capacity under our senior revolving credit facility from $1.3 billion to $1.4 billion. See Financing Activities. Under the terms of the senior revolving credit facility, the borrowing base will be redetermined on an annual basis, with us 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. 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. At December 31, 2010, our availability for future secured borrowings under our senior revolving credit facility was approximately $778.6 million. The daily average outstanding balance for the quarter and year ended December 31, 2010 was $383.7 million and $155.6 million, respectively.

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. At December 31, 2010, the commitments are from a diverse syndicate of 21 lenders and no single lender's commitment represented more than 7% of the total commitments.

In response to market conditions resulting from the recent Gulf of Mexico drilling moratorium in 2010 and as part of our ongoing portfolio optimization, we began the process of divesting our Gulf of Mexico properties and acquiring additional onshore properties. In December 2010, we completed the divestment of our Gulf of Mexico shallow water properties to McMoRan. At closing and after preliminary closing adjustments, we received approximately $86.1 million in cash, which included $11.1 million in working capital adjustments, and 51.0 million shares of McMoRan common stock, in exchange for all our interests in our Gulf of Mexico leasehold located in less than 500 feet of water. The McMoRan shares were valued at approximately $665.9 million based on McMoRan's closing stock price of $17.18 on December 30, 2010 discounted to reflect certain restrictions on the marketability of the McMoRan shares under the registration rights agreement and stockholder agreement entered into by us and McMoRan at the closing of the transaction. The cash proceeds received, net of approximately $8.8 million in transaction costs, were primarily used to repay outstanding borrowings under our credit facilities. The proceeds were recorded as reductions to capitalized costs pursuant to full cost accounting rules. This transaction allows us to retain the upside exposure to our successful shallow water exploration potential while reducing capital expenditure requirements. The McMoRan common stock is subject to certain restrictions on the marketability. Under the terms of the stockholder agreement with McMoRan, we are generally prohibited from transferring any of our shares of McMoRan common stock prior to December 30, 2011. Thereafter, we may sell shares of McMoRan common stock pursuant to underwritten offerings, in periodic sales under a shelf registration statement to be filed by McMoRan (subject to certain volume limitations), pursuant to the exercise of piggyback registration rights or as otherwise permitted by applicable law.

In September 2010, we announced that the data room process for the planned Gulf of Mexico deepwater divestment is underway. The transaction is expected to close in the first half of 2011.

During the fourth quarter of 2010, we completed the acquisition of approximately 60,000 net acres in the Eagle Ford oil and gas condensate windows in South Texas for approximately $596.3 million in cash. We funded the Eagle Ford acquisition primarily with borrowings under our senior revolving credit facility. In conjunction with the acquisition of the Eagle Ford properties, and in anticipation of divesting our deepwater Gulf of Mexico properties, we entered into a series of reverse like-kind exchange agreements pursuant to Section 1031 of the IRC. As a result, certain tax benefits could be achieved with a timely divestment of our Gulf of Mexico deepwater properties.

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 various derivative instruments to manage our exposure to 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 agreements and subjects us to the credit risk of the counterparties to such agreements. 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 – Commodity Price Risk.

Our 2011 capital budget is approximately $1.2 billion, including capitalized interest and general and administrative expenses. We intend to fund our 2011 capital budget from internally generated funds and borrowings under our senior revolving credit facility. In addition, we could curtail the portion of our capital expenditures that is discretionary if our cash flows decline from expected levels.

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 August 3, 2015 and the next maturity of our senior notes will occur on June 15, 2015.

Working Capital

At December 31, 2010, we had a working capital deficit of approximately $130.8 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 August 2010, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and the lenders party thereto, which amended and restated our senior revolving credit facility. The aggregate commitments of the lenders under our senior revolving credit facility are $1.4 billion with an initial borrowing base of $1.6 billion. The borrowing base will be redetermined on an annual basis, with us 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. At December 31, 2010, our availability for future secured borrowings under our senior revolving credit facility was approximately $778.6 million. 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 August 3, 2015. At December 31, 2010, we had $620.0 million in outstanding borrowings and $1.4 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 1.75% to 2.75%; (ii) a variable amount ranging from 0.75% to 1.75% plus 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 plus 1%; or (iii) the overnight federal funds rate plus an additional variable amount ranging from 1.75% to 2.75% for swingline loans. The additional variable amount of interest payable on outstanding borrowings is based on the utilization rate as a percentage of the total amount of funds borrowed under our senior revolving credit facility to the borrowing base. Letter of credit fees under our senior revolving credit facility are based on the utilization rate and range from 1.75% to 2.75%. 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 2.31% at December 31, 2010.

Our senior revolving credit facility is secured by 100% of the shares of stock in certain of our domestic subsidiaries, 65% of the shares of stock in certain foreign subsidiaries and mortgages covering at least 75% of the total present value of our domestic proved oil and gas properties. Our senior revolving credit facility 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 4.50 to 1.

In October 2010, we entered into Consent and Amendment No. 1 to our Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and the lenders party thereto, or the First Amendment, which amends our senior revolving credit facility entered into in August 2010. The First Amendment permits our acquisition and ownership of the McMoRan common stock. Under the First Amendment, the lenders party thereto also consent to the transactions contemplated by the Agreement and Plan of Merger. The other terms and conditions of the senior revolving credit facility remained substantially the same, including our borrowing base.

Short-term Credit Facility. We have an uncommitted short-term unsecured credit facility, or short-term facility, under which we may make borrowings from time to time until June 1, 2011, 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, 2011. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and us.

We borrow under our short-term facility to fund our working capital needs. The funding requirements are typically generated due to the timing differences between payments and receipts associated with our oil and gas production. We generally pay off the short-term facility with receipts from the sales of our oil and gas production or borrowings under our senior revolving credit facility. No amounts were outstanding under the short-term facility at December 31, 2010. The daily average outstanding balance for the quarter and year ended December 31, 2010 was $43.0 million and $30.9 million, respectively. The weighted average interest rate on borrowings under our short-term credit facility was 1.5% for the years ended December 31, 2010 and 2009.

7⅝% Senior Notes due 2020. In March 2010, we issued $300 million of 7⅝% Senior Notes due 2020, at par. We received approximately $294 million of net proceeds, after deducting the underwriting discount and offering expenses. We used the net proceeds to reduce indebtedness outstanding under our senior revolving credit facility and for general corporate purposes. We may redeem all or part of the 7⅝% Senior Notes due 2020 on or after April 1, 2015 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to April 1, 2013 we may, at our option, redeem up to 35% of the 7⅝% Senior Notes due 2020 with the proceeds of certain equity offerings.

The 7¾% Senior Notes due 2015, 10% Senior Notes due 2016, 7% Senior Notes due 2017, 7⅝% Senior Notes due 2018, 8⅝% Senior Notes due 2019 and 7⅝% Senior Notes due 2020 (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 indenture, 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.

Cash Flows

	Year Ended December 31,		
	2010	**2009**	**2008**
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 912.5	$ 499.0	$ 1,371.4
Investing activities	(1,575.3)	(1,280.4)	(227.8)
Financing activities	667.4	471.3	(857.2)

Net cash provided by operating activities was $912.5 million in 2010, $499.0 million in 2009 and $1.4 billion in 2008. The increase in net cash provided by operating activities in 2010 primarily reflects higher operating income in 2010 as a result of higher commodity prices. The decrease in net cash provided by operating activities in 2009 primarily reflects lower operating income as a result of lower commodity prices.

Net cash used in investing activities of $1.6 billion in 2010 primarily reflects additions to oil and gas properties of $1.0 billion and the acquisition of our Eagle Ford Shale properties for $596.3 million, partially offset by a $35.4 million net cash inflow primarily associated with an adjustment to the final settlement of the $1.1 billion payment to Chesapeake in September 2009 related to the prepayment of the Haynesville Carry. 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. Derivative settlements related to derivatives that are not accounted for as hedges and do not contain a significant financing element are reflected as investing activities. Net cash used in 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 provided by financing activities of $667.4 million in 2010 primarily reflects the net increase in borrowings under our senior revolving credit facility of $390.0 million and the net proceeds from the $300 million offering of 7⅝% Senior Notes due 2020. 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 8⅝% Senior Notes due 2019 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 7⅝% Senior Notes due 2018.

Capital Requirements

We have made and will continue to make substantial capital expenditures for the acquisition, development, exploration and production of oil and gas. Our capital budget for 2011, excluding acquisitions, is 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. In addition, we could curtail the portion of our capital expenditures that is discretionary if our cash flows decline from expected levels.

Stock Repurchase Program

Our Board of Directors has authorized the repurchase of shares 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. We currently have $695.8 million in authorized repurchases remaining under the program.

Commitments and Contingencies

We had the following obligations at December 31, 2010 (in thousands):

	Total	2011	2012 and 2013	2014 and 2015	Thereafter
Long-term debt	$ 3,385,000	$ -	$ -	$ 1,220,000	$ 2,165,000
Interest on debt	1,587,838	244,133	488,267	457,500	397,938
Asset retirement obligation	239,432	13,860	10,217	25,086	190,269
Operating leases	91,220	18,352	28,466	22,492	21,910
Drilling rig commitments	74,783	34,736	37,263	2,784	-
Commodity derivative contracts	172,632	61,213	111,419	-	-
Stock compensation awards	14,199	10,603	3,596	-	-
Tax uncertainties	16,132	7,314	6,996	-	1,822
Other	23,916	8,401	12,082	1,572	1,861
	$ 5,605,152	$ 398,612	$ 698,306	$ 1,729,434	$ 2,778,800

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, 2010 remains outstanding to maturity with interest and commitment fees calculated at the rates in effect at December 31, 2010.

Asset retirement obligations represent the estimated fair value at December 31, 2010 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.

Drilling rig commitments represent obligations with certain rig contractors primarily to fulfill our Eagle Ford Shale drilling program.

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

Stock compensation awards represent the net liability for the deemed vested portion of our stock appreciation rights, or SARs. The liability at December 31, 2010 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 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 various service contracts and aircraft maintenance contracts.

Environmental Matters. As discussed under Items 1 and 2 – Business and 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. 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 have 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 2011 cash expenditures related to plugging, abandonment and remediation will be approximately $13.9 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, $70.1 million ($144.1 million undiscounted), is included in our asset retirement obligation as reflected in our 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 $75.0 million). To secure its abandonment obligations, the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2010, the escrow account had a balance of $14.7 million. The fair value of our guarantee at December 31, 2010, $0.3 million, considers the payment/performance risk of the purchaser and is included in other long-term liabilities in our 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. 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. 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 are self-insured for named windstorms in the Gulf of Mexico. 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. 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 natural 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.

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 nine 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, 2010. 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 2010. The commitments under our senior revolving credit facility are from a diverse syndicate of 21 lenders. At December 31, 2010, 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 was first effective for reporting 2009 reserve information. The primary impact of the SEC's final rule on our reserve estimates included: the use of the twelve-month average of the first-day-of-the-month reference prices compared to the year-end reference prices, in each case adjusted for location and quality differentials; certain of our undeveloped locations are not scheduled to be developed within five years, which had the impact of reducing our proved undeveloped reserves; 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. Under the SEC's final rule, prior period reserves were not restated.

In January 2010, the Financial Accounting Standards Board, or 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.

The impact of the adoption of the SEC's final rule on our financial statements was 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. Primarily all of our 2010 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 2010 and 2009 and costs as of the date of the estimate and, in prior years, 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, 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. The new 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 for 2010 and 2009 and year-end prices for 2008, in each case adjusted for location and quality differentials. 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. An impairment is required 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, 2010, the ceiling with respect to our oil and gas properties exceeded the net capitalized costs by 16% and we did not record an impairment. The ceiling limitation is applied separately for each country. During the second quarter of 2010, we completed our interpretation of seismic and drilling data from our two offshore Vietnam exploratory wells and decided not to pursue additional exploratory activities in this area. The costs related to our Vietnam oil and gas properties not subject to amortization were transferred to our Vietnam full cost pool where they were subject to the ceiling limitation. Because our Vietnam full cost pool had no associated proved oil and gas reserves, we recorded a non-cash pre-tax impairment charge of $59.5 million. We also recorded a corresponding tax benefit of $23.0 million.

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.

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, 2010, we had approximately $3.3 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 60% of the costs not subject to amortization at December 31, 2010 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 these transfers 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 full cost ceiling test previously discussed. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expense. We are unable to predict changes in future development costs as such costs are dependent on the success of our development program, as well as future economic conditions.

Our oil and gas DD&A rate for 2011, after the effect of the fourth quarter acquisitions and divestments, is expected to be $16.28 per BOE. Based on our estimated proved reserves and our net oil and gas properties subject to amortization at December 31, 2010: (i) a 5.0% increase in our costs subject to amortization would increase our DD&A rate by approximately $0.81 per BOE and (ii) a 5.0% negative revision to proved reserves would increase our DD&A rate by approximately $0.85 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 counterparties' credit quality for asset balances and our credit quality for liability. 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 counterparties' 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 – Commodity Price 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 for exercises 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 $51 million, $61 million and $50 million of stock-based compensation expense for the years ended December 31, 2010, 2009 and 2008, 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, 2010, goodwill totaled $535 million and represented approximately 6% 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.

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.

The first step of the goodwill impairment test requires that we make an estimate of the fair value of the reporting unit. Quoted market prices in active markets are the best evidence of fair value. We estimate the fair value of the reporting unit by applying 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. This requires that we make certain judgments about the selection of merger and acquisition transactions and transaction premiums.

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 the fair value of our reporting unit may be below its carrying amount. Due to adverse market conditions affecting the oil and gas industry in the second quarter of 2010, we performed an interim goodwill impairment test as of June 30, 2010. Based on that test, we concluded that the fair value of the reporting unit exceeded the carrying value of the reporting unit by 13%; therefore, the second step of the goodwill impairment test was not required. In addition, we completed the divestment of our Gulf of Mexico shallow water shelf properties on December 30, 2010 and performed our annual goodwill impairment test, as described above, on December 31, 2010.

Events affecting oil and gas prices may cause a decrease in the fair value of the reporting unit, and 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.

Income Taxes. The amount of income taxes recorded by us requires interpretations of complex rules and regulations of various tax jurisdictions. We recognize deferred tax assets and liabilities for temporary differences, operating losses and tax credit carryforwards. Also, we routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. We routinely assess potential uncertain tax positions and, if required, establish accruals for such amounts. The accruals for deferred tax assets and liabilities are subject to a significant amount of judgment and are reviewed and adjusted routinely based on changes in facts and circumstances. Although we consider our tax accruals adequate, material changes in these accruals may occur in the future, based on the progress of ongoing tax audits, changes in legislation and resolution of other pending tax matters.

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 adopted the provisions of this standard effective January 1, 2010, and it did not have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued authoritative guidance clarifying the acquisition date that should be used for reporting the pro forma financial information disclosures when comparative financial statements are presented. The guidance also improves the usefulness of the pro forma revenue and earnings disclosures by requiring a description of the nature and amount of material, nonrecurring pro forma adjustments that are directly attributable to the business combination. The guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued authoritative guidance amending the criteria for performing the second step of the goodwill impairment test for companies with reporting units with zero or negative carrying amounts. The amended guidance requires performance of the second step if qualitative factors indicate that it is more likely than not that a goodwill impairment exists. This guidance is effective for fiscal years beginning after December 15, 2010, and for interim periods within that first reporting period. Early adoption is not permitted. We do not expect this guidance to have a significant 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. The markets for oil and gas have historically 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 7 – 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, 2010, we had the following outstanding commodity derivative contracts, all of which settle monthly:

Period	Instrument Type	Daily Volumes	Average Price (1)	Average Deferred Premium	Index
Sales of Crude Oil Production					
2011					
Jan - Dec	Put options (2)	31,000 Bbls	$80.00 Floor with a $60.00 Limit	$5.023 per Bbl	WTI
Jan - Dec	Three-way collars (3)	9,000 Bbls	$80.00 Floor with a $60.00 Limit $110.00 Ceiling	$1.00 per Bbl	WTI
2012					
Jan - Dec	Put options (2)	40,000 Bbls	$80.00 Floor with a $60.00 Limit	$6.087 per Bbl	WTI
Sales of Natural Gas Production					
2011					
Jan - Dec	Three-way collars (4)	200,000 MMBtu	$4.00 Floor with a $3.00 Limit $4.92 Ceiling	-	Henry Hub
2012					
Jan - Dec	Put options (5)	160,000 MMBtu	$4.30 Floor with a $3.00 Limit	$0.294 per MMBtu	Henry Hub

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

(2) If the index price is less than the $80 per barrel floor, we receive the difference between the $80 per barrel floor and the index price up to a maximum of $20 per barrel less the option premium. If the index price is at or above $80 per barrel, we pay only the option premium.

(3) If the index price is less than the $80 per barrel floor, we receive the difference between the $80 per barrel floor and the index price up to a maximum of $20 per barrel less the option premium. We pay the difference between the index price and $110 per barrel plus the option premium if the index price is greater than the $110 per barrel ceiling. If the index price is at or above $80 per barrel but at or below $110 per barrel, we pay only the option premium.

(4) If the index price is less than the $4.00 per MMBtu floor, we receive the difference between the $4.00 per MMBtu floor and the index price up to a maximum of $1.00 per MMBtu. We pay the difference between the index price and $4.92 per MMBtu if the index price is greater than the $4.92 per MMBtu ceiling. If the index price is at or above $4.00 per MMBtu but at or below $4.92 per MMBtu, no cash settlement is required.

(5) If the index price is less than the $4.30 per MMBtu floor, we receive the difference between the $4.30 per MMBtu floor and the index price up to a maximum of $1.30 per MMBtu less the option premium. If the index price is at or above $4.30 per MMBtu, we pay only the option premium.

For put options, we pay a premium to the counterparty in exchange for the sale of the instrument. If the index price is below the floor price of the put option, we receive the difference between the floor price and the index price multiplied by the contract volumes less the option premium. If the index price settles at or above the floor 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 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 and is less than the ceiling price, then no payment, other than the premium, may be 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 natural gas commodity derivative instruments at December 31, 2010 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	$ 88	$ (31)	$ 48
Crude oil collars	-	(12)	11
Natural gas collars	(10)	(20)	19
Natural put options	15	(5)	7
	$ 93	$ (68)	$ 85

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 49% of our gas production is sold monthly using 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, 2010, $620.0 million was outstanding under our senior revolving credit facility at an effective interest rate of 2.31%. 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 $620.0 million outstanding under our senior revolving credit facility at December 31, 2010, on an annualized basis a 1% change in the effective interest rate would result in a $6.2 million change in our interest costs.

Equity Price Risk

We are exposed to market risk because we own an equity investment in McMoRan common stock. See Note 6 – Investment and Note 7 – Fair Value Measurements of Assets and Liabilities in the accompanying financial statements for a discussion of our equity investment. At December 31, 2010, the investment, comprised of 51.0 million shares of McMoRan common stock, was valued at approximately $664.3 million. A 10% change in the underlying equity market price per share would result in a $66.4 million increase or decrease in the fair value of our investment, recognized in the income statement.

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, 2010 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, 2010.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010 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, 2010 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

On February 23, 2011, the Board of Directors amended the Company's Bylaws to provide for majority voting of directors in uncontested elections. In contested elections, directors will be elected using a plurality standard.

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 2011 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2010, 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, 2011 and their business experience for the last five years.

Directors

James C. Flores, age 51, 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. (now owned by Vulcan Energy Corporation), from May 2001 to June 2004 and is currently a director of Vulcan Energy and McMoRan Exploration Co. 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 75, Director since May 2004. He was also 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 64, 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 70, Director since September 2002. He was also 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 70, Director since September 2002. He was also 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 66, Director since November 2007. He was also a director of Pogo 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.

Charles G. Groat, age 70, 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 at the University of Texas at Austin. Before joining the University of Texas at Austin, Dr. Groat served for more than six years as Director of the U.S. Geological Survey, having been appointed by President Clinton and retained by President Bush.

John H. Lollar, age 72, Director since September 2002. He was also 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 51, 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. (now owned by Vulcan Energy Corporation), from May 2001 to June 2004 and is currently a director of Vulcan Energy and McMoRan Exploration Co. 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 53, 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 48, 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 49, Executive Vice President, General Counsel and Secretary since September 2003. He was also Plains Resources' Executive Vice President, General Counsel, and Secretary from September 2003 to June 2004. Mr. Wombwell currently serves on the boards of McMoRan Exploration Co. and the Houston Arboretum. He was previously a partner at the law firm of Andrews Kurth LLP with a practice focused on representing public companies 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 2011 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 2011 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 2011 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 2011 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	Agreement and Plan of Merger, dated September 19, 2010, by and among Plains Exploration & Production Company, PXP Gulf Properties LLC, PXP Offshore LLC and McMoRan Exploration Co., McMoRan Oil & Gas LLC, McMoRan GOM, LLC and McMoRan Offshore LLC (incorporated by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q for the period ending September 30, 2010, File No. 1-31470).
2.2	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).
2.3	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).
2.4	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, or the 2008 10-K).
2.5	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).
2.6	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).
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* Amended and Restated Bylaws of Plains Exploration & Production Company.

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 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 September 11, 2009, File No. 1-31470).

4.12 Eleventh Supplemental Indenture, dated as of March 29, 2010, to Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, the subsidiary guarantor 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 29, 2010, File No. 1-31470).

4.13 Amended and Restated Credit Agreement, dated as of August 3, 2010, 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 August 5, 2010, File No. 001-31470).

4.14 Consent and Amendment No.1 to Amended and Restated Credit Agreement, dated as of October 8, 2010, 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 October 12, 2010, 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).

10.4 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).

10.5+ Plains Exploration & Production Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.7 to the 2007 10-K).

10.6+ 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).

10.7+ Form of Restricted Stock Unit Agreement under the 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.9 to the 2009 10-K).

10.8+	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).
10.9+	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).
10.10+	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).
10.11+	Form of Restricted Stock Unit Agreement under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 to the 2009 10-K).
10.12+	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).
10.13+	Amended and Restated Plains Exploration & Production Company Executives' Long-Term Retention and Deferred Compensation Agreement effective as of February 10, 2006 (incorporated by reference to Exhibit 10.15 to the 2007 10-K).
10.14+	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).
10.15+	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).
10.16+	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).
10.17+	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).
10.18+	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).
10.19+	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).
10.20+	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).
10.21	Form of Election for Director Deferral of Restricted Stock Awards (incorporated by reference to Exhibit 10.23 to the 2008 10-K).
10.22	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).

10.23+	Plains Exploration & Production Company 2010 Incentive Award Plan (incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on March 30, 2010, File No. 1-31470).
10.24+*	Form of Plains Stock Appreciation Rights Agreement under the 2010 Incentive Plan.
10.25+*	Form of Plains Restricted Stock Award Agreement under the 2010 Incentive Plan.
10.26+*	Form of Restricted Stock Unit Agreement under the 2010 Incentive Award Plan.
10.27+*	Restricted Stock Unit Agreement, effective as of November 4, 2010, between Plains Exploration & Production Company and James C. Flores.
10.28	Registration Rights Agreement, dated December 30, 2010, by and between Plains Exploration & Production Company and McMoRan Exploration Co. (incorporated by reference to Exhibit 10.1 to PXP's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 6, 2011).
10.29	Stockholder Agreement, dated December 30, 2010, by and between Plains Exploration & Production Company and McMoRan Exploration Co. (incorporated by reference to Exhibit 10.2 to PXP's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 6, 2011).
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.
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., 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 24, 2011	/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 24, 2011	/s/ James C. Flores James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: February 24, 2011	/s/ Isaac Arnold, Jr. Isaac Arnold, Jr., Director
Date: February 24, 2011	/s/ Alan R. Buckwalter, III Alan R. Buckwalter, III, Director
Date: February 24, 2011	/s/ Jerry L. Dees Jerry L. Dees, Director
Date: February 24, 2011	/s/ Tom H. Delimitros Tom H. Delimitros, Director
Date: February 24, 2011	/s/ Thomas A. Fry, III Thomas A. Fry, III, Director
Date: February 24, 2011	/s/ Charles G. Groat Charles G. Groat, Director
Date: February 24, 2011	/s/ John H. Lollar John H. Lollar, Director
Date: February 24, 2011	/s/ Winston M. Talbert Winston M. Talbert, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 24, 2011	/s/ Nancy I. Williams Nancy I. Williams, 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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 17 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.

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 24, 2011

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

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	$ 6,434	$ 1,859
Accounts receivable	269,024	258,585
Commodity derivative contracts	-	11,952
Inventories	24,406	19,934
Deferred income taxes	74,086	-
Prepaid expenses and other current assets	28,937	14,305
	402,887	306,635
Property and Equipment, at cost		
Oil and natural gas properties - full cost method		
Subject to amortization	9,975,056	9,044,146
Not subject to amortization	3,304,554	3,279,537
Other property and equipment	137,150	125,667
	13,416,760	12,449,350
Less allowance for depreciation, depletion, amortization and impairment	(6,196,008)	(5,616,628)
	7,220,752	6,832,722
Goodwill	535,144	535,237
Investment	664,346	-
Other Assets	71,808	60,137
	$ 8,894,937	$ 7,734,731
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 284,628	$ 248,454
Commodity derivative contracts	52,971	59,176
Royalties and revenues payable	70,990	78,590
Interest payable	49,127	45,743
Deferred income taxes	-	153,473
Other current liabilities	75,973	97,115
	533,689	682,551
Long-Term Debt	3,344,717	2,649,689
Other Long-Term Liabilities		
Asset retirement obligation	225,571	214,231
Commodity derivative contracts	24,740	-
Other	28,205	55,531
	278,516	269,762
Deferred Income Taxes	1,355,050	933,748
Commitments and Contingencies (Note 11)		
Stockholders' Equity		
Common stock, $0.01 par value, 250.0 million shares authorized, 143.9 million shares issued at December 31, 2010 and 2009	1,439	1,439
Additional paid-in capital	3,427,869	3,381,566
Retained earnings	148,620	51,204
Treasury stock, at cost, 3.8 million shares and 4.5 million shares at December 31, 2010 and 2009, respectively	(194,963)	(235,228)
	3,382,965	3,198,981
	$ 8,894,937	$ 7,734,731

See notes to consolidated financial statements.

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

	Year Ended December 31, 2010	2009	2008
Revenues			
Oil sales	$ 1,142,760	$ 903,146	$ 1,766,677
Gas sales	399,607	281,978	619,886
Other operating revenues	2,228	2,006	16,908
	1,544,595	1,187,130	2,403,471
Costs and Expenses			
Lease operating expenses	262,533	250,916	327,412
Steam gas costs	66,449	53,801	131,156
Electricity	42,794	43,891	52,735
Production and ad valorem taxes	29,446	38,708	93,988
Gathering and transportation expenses	50,680	36,651	21,137
General and administrative	136,437	144,586	153,306
Depreciation, depletion and amortization	533,416	407,248	608,448
Impairment of oil and gas properties	59,475	-	3,629,666
Accretion	17,702	14,332	13,036
Legal recovery	(8,423)	(87,272)	-
Other operating (income) expense	(4,130)	2,136	-
	1,186,379	904,997	5,030,884
Income (Loss) from Operations	358,216	282,133	(2,627,413)
Other Income (Expense)			
Gain on sale of assets	-	-	65,689
Interest expense	(106,713)	(73,811)	(116,991)
Debt extinguishment costs	(1,189)	(12,093)	(18,256)
(Loss) gain on mark-to-market derivative contracts	(60,695)	(7,017)	1,555,917
Other income (expense)	14,391	27,968	(12,575)
Income (Loss) Before Income Taxes	204,010	217,180	(1,153,629)
Income tax benefit (expense)			
Current	93,090	(45,091)	(230,815)
Deferred	(193,835)	(35,784)	675,350
Net Income (Loss)	$ 103,265	$ 136,305	$ (709,094)
Earnings (Loss) Per Share			
Basic	$ 0.74	$ 1.10	$ (6.52)
Diluted	$ 0.73	$ 1.09	$ (6.52)
Weighted Average Shares Outstanding			
Basic	140,438	124,405	108,828
Diluted	141,897	125,288	108,828

See notes to consolidated financial statements.

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

	Year Ended December 31, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 103,265	$ 136,305	$ (709,094)
Items not affecting cash flows from operating activities			
Gain on sale of assets	-	-	(65,689)
Depreciation, depletion and amortization	533,416	407,248	608,448
Impairment of oil and gas properties	59,475	-	3,629,666
Accretion	17,702	14,332	13,036
Deferred income tax expense (benefit)	193,835	35,784	(675,350)
Debt extinguishment costs	1,189	12,093	18,256
Loss (gain) on mark-to-market derivative contracts	60,695	7,017	(1,555,917)
Non-cash compensation	50,875	60,490	50,401
Other non-cash items	2,594	6,950	6,546
Change in assets and liabilities from operating activities			
Accounts receivable and other assets	(41,604)	(26,600)	120,761
Inventories	(4,502)	760	(4,782)
Accounts payable and other liabilities	(30,785)	(46,751)	(109,182)
Stock appreciation rights	(566)	(355)	(59,078)
Income taxes receivable/payable	(33,119)	(108,227)	103,387
Net cash provided by operating activities	912,470	499,046	1,371,409
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to oil and gas properties	(1,048,858)	(1,628,357)	(1,116,715)
Acquisition of oil and gas properties	(554,685)	(1,159,939)	(2,006,127)
Acquisition of Pogo Producing Company	-	-	(77,686)
Proceeds from sales of oil and gas properties and related assets, net of costs and expenses	73,965	-	2,969,945
Derivative settlements	(29,921)	1,522,412	(8,606)
Decrease in restricted cash	-	-	59,092
Additions to other property and equipment	(15,809)	(14,677)	(44,436)
Other	-	162	(3,257)
Net cash used in investing activities	(1,575,308)	(1,280,399)	(227,790)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from revolving credit facilities	3,332,610	3,513,325	14,331,046
Repayments of revolving credit facilities	(2,942,610)	(4,588,325)	(15,231,046)
Proceeds from issuance of Senior Notes	300,000	916,439	400,000
Costs incurred in connection with financing arrangements	(22,771)	(19,556)	(27,527)
Derivative settlements	-	1,392	(25,678)
Issuance of common stock	-	648,005	-
Purchase of treasury stock	-	-	(304,192)
Other	184	57	207
Net cash provided by (used in) financing activities	667,413	471,337	(857,190)
Net increase (decrease) in cash and cash equivalents	4,575	(310,016)	286,429
Cash and cash equivalents, beginning of period	1,859	311,875	25,446
Cash and cash equivalents, end of period	$ 6,434	$ 1,859	$ 311,875

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2010	2009	2008
Net Income (Loss)	$ 103,265	$ 136,305	$ (709,094)
Other Comprehensive Income (Loss)			
Pension liability adjustment	-	1,094	(3,616)
Pension related tax (expense) benefit	-	(410)	1,366
	-	684	(2,250)
Comprehensive Income (Loss)	$ 103,265	$ 136,989	$ (711,344)

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, 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	-	-	(42,416)	-	-	764	42,416	-
Other comprehensive income	-	-	-	-	684	-	-	684
Exercise of stock options and other	-	-	32	-	-	7	45	77
Balance at December 31, 2009	143,924	1,439	3,381,566	51,204	-	(4,512)	(235,228)	3,198,981
Net income	-	-	-	103,265	-	-	-	103,265
Restricted stock awards	-	-	80,515	-	-	-	-	80,515
Issuance of treasury stock for restricted stock awards	-	-	(34,209)	(4,954)	-	728	39,163	-
Exercise of stock options and other	-	-	(3)	(895)	-	20	1,102	204
Balance at December 31, 2010	143,924	$ 1,439	$ 3,427,869	$ 148,620	$ -	(3,764)	$ (194,963)	$ 3,382,965

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 located in the United States.

Our consolidated financial statements include the accounts of all our wholly owned subsidiaries and a variable interest entity for which we are the primary beneficiary. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to prior year statements to conform to the current year presentation.

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) valuation of our investment; (5) allocating purchase price in connection with business combinations and determining fair value, including goodwill; (6) income taxes; (7) accrued assets and liabilities; (8) stock-based compensation; (9) asset retirement obligations and (10) 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 17 – 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 17 – 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".

During the second quarter of 2010, we completed our interpretation of seismic and drilling data from our two offshore Vietnam exploratory wells and decided not to pursue additional exploratory activities in this area. We have submitted a notice to the Vietnam state oil company in order to terminate our production sharing contract in accordance with its terms. The costs related to our Vietnam oil and gas properties not subject to amortization were transferred to our Vietnam full cost pool where they were subject to the ceiling limitation. Because our Vietnam full cost pool had no associated proved oil and gas reserves, we recorded a non-cash pre-tax impairment charge of $59.5 million. We also recorded a corresponding tax benefit of $23.0 million.

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 consist 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, 2010 and 2009 included $4.3 million and $5.3 million, respectively, representing outstanding checks that had not been presented for payment.

Inventory. Oil inventories are carried at the lower of the cost to produce or market value, and materials and supplies inventories are stated at the lower of cost or market with cost determined on an average cost method. At December 31, 2010 and 2009, inventory consisted of the following (in thousands):

	December 31, 2010	December 31, 2009
Oil	$ 6,744	$ 6,488
Materials and supplies	17,662	13,446
	$ 24,406	$ 19,934

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 10 – 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, 2010 or 2009.

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.

Investment. We have elected to measure our investment at fair value with changes in fair value included in our income statement. If we had not elected the fair value method, the investment would have qualified for the equity method of accounting, under which our proportionate share of the investee's income would have been reported in our income statement. See Note 6 – Investment and Note 7 – Fair Value Measurements of Assets and Liabilities.

Fair Value. 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 investment and determine their placement within the fair value hierarchy levels as described above. See Note 7 – 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, 2010, goodwill totaled $535 million and represented approximately 6% 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.

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.

The first step of the goodwill impairment test requires that we make an estimate of the fair value of the reporting unit. Quoted market prices in active markets are the best evidence of fair value. We estimate the fair value of the reporting unit by applying 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. This requires that we make certain judgments about the selection of merger and acquisition transactions and transaction premiums.

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 the fair value of our reporting unit may be below its carrying amount. Due to the adverse market conditions affecting the oil and gas industry in the second quarter of 2010, we performed an interim goodwill impairment test as of June 30, 2010. Based on that test, we concluded that the fair value of the reporting unit exceeded the carrying value of the reporting unit by 13%; therefore, the second step of the goodwill impairment test was not required. In addition, we completed the divestment of our Gulf of Mexico shallow water shelf properties on December 30, 2010 and performed our annual goodwill impairment test, as described above, on December 31, 2010.

Events affecting oil and gas prices may cause a decrease in the fair value of the reporting unit, and 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 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.

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 9 – Stock-Based and Other Compensation Plans.

Pension. As a result of our acquisition of Pogo Producing Company we recorded assets and liabilities for a defined benefit pension plan. 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 Financial Accounting Standards Board, or 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 adopted the provisions of this standard effective January 1, 2010, and it did not have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued authoritative guidance clarifying the acquisition date that should be used for reporting the pro forma financial information disclosures when comparative financial statements are presented. The guidance also improves the usefulness of the pro forma revenue and earnings disclosures by requiring a description of the nature and amount of material, nonrecurring pro forma adjustments that are directly attributable to the business combination. The guidance is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued authoritative guidance amending the criteria for performing the second step of the goodwill impairment test for companies with reporting units with zero or negative carrying amounts. The amended guidance requires performance of the second step if qualitative factors indicate that it is more likely than not that a goodwill impairment exists. This guidance is effective for fiscal years beginning after December 15, 2010, and for interim periods within that first reporting period. Early adoption is not permitted. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

Note 2 — Acquisitions

Eagle Ford

During the fourth quarter of 2010, we completed the acquisition of approximately 60,000 net acres in the Eagle Ford oil and gas condensate windows in South Texas for approximately $596.3 million in cash. We funded the acquisition primarily with borrowings under our senior revolving credit facility.

In conjunction with the acquisition of the Eagle Ford properties, and in anticipation of divesting our deepwater Gulf of Mexico properties, we entered into a series of reverse like-kind exchange agreements pursuant to Section 1031 of the Internal Revenue Code, or IRC. The purchase consideration related to the Eagle Ford properties was loaned by PXP to the qualified intermediary, PXP Operations LLC, to facilitate the potential tax deferred reverse like-kind exchange treatment under IRC 1031.

Since PXP Operations' equity at risk is insufficient to permit PXP Operations to carry on its activities without additional subordinated financial support, PXP Operations meets the criteria for a variable interest entity. PXP is the primary beneficiary for accounting purposes because we have the power to direct the most significant activities that impact PXP Operations' economic performance through a management agreement. In addition, we have the obligation to absorb a majority of the losses or receive a majority of the benefits that could potentially be significant to the variable interest entity. As a result, we consolidate PXP Operations in our consolidated financial statements. The carrying amounts associated with PXP Operations, after eliminating the effect of intercompany transactions, were as follows (in thousands):

	December 31, 2010
Assets	
Accounts receivable	$ 5,608
Other	24
Oil and natural gas properties - full cost method	
Subject to amortization - net	65,571
Not subject to amortization	551,716
	$ 622,919
Liabilities	
Accounts payable	$ 20,946
Other	3,063
Net carrying amount	$ 598,910

Chesapeake Participation Agreement

In July 2008, we acquired from a subsidiary of Chesapeake Energy Corporation a 20% interest in Chesapeake's Haynesville Shale leasehold for approximately $1.65 billion in cash, funded 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.

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 issuance of $400 million of 8$^{5}/_{8}$% Senior Notes due 2019, cash on hand and borrowings under 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. As a result of the prepayment of the Haynesville Carry, we do not pay promoted well costs for costs attributable to periods subsequent to the third quarter of 2009. During 2010 and 2009, we spent $16 million and $59 million, respectively, to acquire approximately 1,200 and 5,000 net additional acres in the Haynesville Shale. At December 31, 2010 we had approximately 105,000 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. The effective date of the transaction was January 1, 2008.

Piceance Basin Properties

In June 2008, PXP and a subsidiary of Occidental Petroleum Corporation, or Oxy, acquired equal shares of working interests in acreage in the Piceance Basin in Colorado adjacent to the Piceance Basin properties we acquired in May 2007. 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 December 2008, we sold our interest in these acres to Oxy. See Note 3 – Divestments. Oxy assumed our obligation for the unpaid consideration in connection with the sale.

Note 3 — Divestments

In December 2010, we completed the divestment of our Gulf of Mexico shallow water shelf properties to McMoRan Exploration Co. At closing and after preliminary closing adjustments, we received approximately $86.1 million in cash, which included $11.1 million in working capital adjustments, and 51.0 million shares of McMoRan common stock, in exchange for all our interests in our Gulf of Mexico leasehold located in less than 500 feet of water. The transaction was completed pursuant to an Agreement and Plan of Merger dated as of September 19, 2010, and effective as of August 1, 2010, between us and certain of our subsidiaries and McMoRan and certain of its subsidiaries. The McMoRan shares were valued at approximately $665.9 million based on McMoRan's closing stock price of $17.18 on December 30, 2010 discounted to reflect certain restrictions on the marketability of the McMoRan shares under the registration rights agreement and stockholder agreement entered into by us and McMoRan at the closing of the transaction. The cash proceeds received, net of approximately $8.8 million in transaction costs, were primarily used to repay outstanding borrowings under our credit facilities. The proceeds were recorded as reductions to capitalized costs pursuant to full cost accounting rules.

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 in the Mesaverde geologic section of the Piceance Basin in Colorado, including a 50% interest in the entity that held our 25% interest in the associated midstream assets, Collbran Valley Gas Gathering LLC, or CVGG. We acquired these properties in May 2007. 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. 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, 2010 and 2009, long-term debt consisted of (in thousands):

	December 31,	
	2010	2009
Senior revolving credit facility	$ 620,000	$ 230,000
7¾% Senior Notes due 2015	600,000	600,000
10% Senior Notes due 2016 (1)	530,812	526,222
7% Senior Notes due 2017	500,000	500,000
7⅝% Senior Notes due 2018	400,000	400,000
8⅝% Senior Notes due 2019 (2)	393,905	393,467
7⅝% Senior Notes due 2020	300,000	-
	$ 3,344,717	$ 2,649,689

(1) The amount is net of unamortized discount of $34.2 million and $38.8 million at December 31, 2010 and December 31, 2009, respectively.
(2) The amount is net of unamortized discount of $6.1 million and $6.5 million at December 31, 2010 and December 31, 2009, respectively.

As of December 31, 2010, aggregate total maturities of long-term debt in the next five years are $1.2 billion in 2015.

Senior Revolving Credit Facility. In August 2010, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and the lenders party thereto, which amended and restated our senior revolving credit facility. The aggregate commitments of the lenders under our senior revolving credit facility are $1.4 billion with an initial borrowing base of $1.6 billion. The borrowing base will be redetermined on an annual basis, with us 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 August 3, 2015. At December 31, 2010, we had $1.4 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 1.75% to 2.75%; (ii) a variable amount ranging from 0.75% to 1.75% plus 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 plus 1%; or (iii) the overnight federal funds rate plus an additional variable amount ranging from 1.75% to 2.75% for swingline loans. The additional variable amount of interest payable on outstanding borrowings is based on the utilization rate as a percentage of the total amount of funds borrowed under our senior revolving credit facility to the borrowing base. Letter of credit fees under our senior revolving credit facility are based on the utilization rate and range from 1.75% to 2.75%. Commitment fees are 0.50% of the amount available for borrowing. The effective interest rate on borrowings under our senior revolving credit facility was 2.31% at December 31, 2010.

Our senior revolving credit facility is secured by 100% of the shares of stock in certain of our domestic subsidiaries, 65% of the shares of stock in certain foreign subsidiaries and mortgages covering at least 75% of the total present value of our domestic proved oil and gas properties. Our senior revolving credit facility 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 4.50 to 1.

In October 2010, we entered into Consent and Amendment No. 1 to our Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and the lenders party thereto, or the First Amendment, which amends our senior revolving credit facility entered into in August 2010. The First Amendment permits our acquisition and ownership of the McMoRan common stock. Under the First Amendment, the lenders party thereto also consent to the transactions contemplated by the Agreement and Plan of Merger. The other terms and conditions of the senior revolving credit facility remained substantially the same, including our borrowing base.

Short-term Credit Facility. We have an uncommitted short-term unsecured credit facility, or short-term facility, under which we may make borrowings from time to time until June 1, 2011, 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, 2011. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and us.

We borrow under our short-term facility to fund our working capital needs. The funding requirements are typically generated due to the timing differences between payments and receipts associated with our oil and gas production. We generally pay off the short-term facility with receipts from the sales of our oil and gas production or borrowings under our senior revolving credit facility. No amounts were outstanding under the short-term facility at December 31, 2010. The daily average outstanding balance for the quarter and year ended December 31, 2010 was $43.0 million and $30.9 million, respectively. The weighted average interest rate on borrowings under our short-term credit facility was 1.5% for the years ended December 31, 2010 and 2009.

7⅝% Senior Notes due 2020. In March 2010, we issued $300 million of 7⅝% Senior Notes due 2020, at par. We received approximately $294 million of net proceeds, after deducting the underwriting discount and offering expenses. We used the net proceeds to reduce indebtedness outstanding under our senior revolving credit facility and for general corporate purposes. We may redeem all or part of the 7⅝% Senior Notes due 2020 on or after April 1, 2015 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to April 1, 2013 we may, at our option, redeem up to 35% of the 7⅝% Senior Notes due 2020 with the proceeds of certain equity offerings.

8⅝% Senior Notes. In September 2009, we issued $400 million of 8⅝% Senior Notes due 2019, or the 8⅝% Senior Notes, 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, at 92.373% of the face value to yield 11.625% to maturity. In April 2009, an additional $200 million of 10% Senior Notes 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 due 2018. In May 2008, we issued $400 million of 7⅝% Senior Notes due 2018, 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 due 2018 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 due 2018 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.

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.

Our 7¾% Senior Notes, 10% Senior Notes, 7% Senior Notes, 7⅝% Senior Notes due 2018, 8⅝% Senior Notes and 7⅝% Senior Notes due 2020 (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 2010, 2009 and 2008, we recognized $1.2 million, $12.1 million and $18.3 million, respectively, of debt extinguishment costs in connection with reductions in our borrowing base and commitments under our senior revolving credit facility.

Note 5 — Commodity Derivative Contracts

General

We are exposed to various market risks, including volatility in oil and gas commodity prices and interest 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 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.

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 the instrument. If the index price is below the floor price of the put option, we receive the difference between the floor price and the index price multiplied by the contract volumes less the option premium. If the index price settles at or above the floor 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 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 and is less than the ceiling price, then no payment, other than the premium, may be 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 April 2010, we entered into crude oil put option spread contracts on 31,000 BOPD for 2011 and 40,000 BOPD for 2012. Additionally, during April 2010 we acquired crude oil three-way collars on 9,000 BOPD for 2011. In November 2010, we acquired natural gas three-way collars on 200,000 MMBtu per day for 2011 and natural gas put options on 160,000 MMBtu per day for 2012.

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 7 – Fair Value Measurements of Assets and Liabilities, for additional discussion on the fair value measurement of our derivative contracts.

As of December 31, 2010, we had the following outstanding commodity derivative contracts, all of which settle monthly:

Period	Instrument Type	Daily Volumes	Average Price (1)	Average Deferred Premium	Index
Sales of Crude Oil Production					
2011					
Jan - Dec	Put options (2)	31,000 Bbls	$80.00 Floor with a $60.00 Limit	$5.023 per Bbl	WTI
Jan - Dec	Three-way collars (3)	9,000 Bbls	$80.00 Floor with a $60.00 Limit $110.00 Ceiling	$1.00 per Bbl	WTI
2012					
Jan - Dec	Put options (2)	40,000 Bbls	$80.00 Floor with a $60.00 Limit	$6.087 per Bbl	WTI
Sales of Natural Gas Production					
2011					
Jan - Dec	Three-way collars (4)	200,000 MMBtu	$4.00 Floor with a $3.00 Limit $4.92 Ceiling	-	Henry Hub
2012					
Jan - Dec	Put options (5)	160,000 MMBtu	$4.30 Floor with a $3.00 Limit	$0.294 per MMBtu	Henry Hub

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

(2) If the index price is less than the $80 per barrel floor, we receive the difference between the $80 per barrel floor and the index price up to a maximum of $20 per barrel less the option premium. If the index price is at or above $80 per barrel, we pay only the option premium.

(3) If the index price is less than the $80 per barrel floor, we receive the difference between the $80 per barrel floor and the index price up to a maximum of $20 per barrel less the option premium. We pay the difference between the index price and $110 per barrel plus the option premium if the index price is greater than the $110 per barrel ceiling. If the index price is at or above $80 per barrel but at or below $110 per barrel, we pay only the option premium.

(4) If the index price is less than the $4.00 per MMBtu floor, we receive the difference between the $4.00 per MMBtu floor and the index price up to a maximum of $1.00 per MMBtu. We pay the difference between the index price and $4.92 per MMBtu if the index price is greater than the $4.92 per MMBtu ceiling. If the index price is at or above $4.00 per MMBtu but at or below $4.92 per MMBtu, no cash settlement is required.

(5) If the index price is less than the $4.30 per MMBtu floor, we receive the difference between the $4.30 per MMBtu floor and the index price up to a maximum of $1.30 per MMBtu less the option premium. If the index price is at or above $4.30 per MMBtu, we pay only the option premium.

Balance Sheet

At December 31, 2010 and 2009, we had the following outstanding commodity derivative contracts recorded in our balance sheet (in thousands):

		Estimated Fair Value Year Ended December 31,	
Instrument Type	**Balance Sheet Classification**	**2010**	**2009**
Crude oil puts	Commodity derivative contracts - current asset	$ 23,910	$ 15,173
Natural gas collars	Commodity derivative contracts - current (liability) asset	(10,469)	14,312
Crude oil collars	Commodity derivative contracts - current liability	(317)	-
Crude oil puts	Commodity derivative contracts - non-current asset	64,266	-
Natural gas puts	Commodity derivative contracts - non-current asset	15,254	-
Total derivative instruments		$ 92,644	$ 29,485

The following table provides supplemental information to reconcile the fair value of our derivative contracts to our balance sheet at December 31, 2010 and 2009, considering the deferred premiums, accrued interest and related settlement payable amounts which are not included in the fair value amounts disclosed in the table above (in thousands):

	Year Ended December 31,	
	2010	**2009**
Net fair value asset	$ 92,644	$ 29,485
Deferred premium and accrued interest on derivative contracts	(164,155)	(73,305)
Settlement payable	(6,200)	(3,404)
Net commodity derivative liability	$ (77,711)	$ (47,224)
Commodity derivative contracts - current asset	$ -	$ 11,952
Commodity derivative contracts - current liability	(52,971)	(59,176)
Commodity derivative contracts - non-current liability	(24,740)	-
	$ (77,711)	$ (47,224)

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, 2010, 2009 and 2008, pre-tax amounts recognized in our income statement for derivative transactions were as follows (in thousands):

	Year Ended December 31,		
	2010	**2009**	**2008**
(Loss) gain on mark-to-market derivative contracts	$ (60,695)	$ (7,017)	$ 1,555,917

Cash Payments and Receipts

During the years ended December 31, 2010, 2009 and 2008, cash (payments) receipts for derivatives were as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Oil derivatives			
Settlements	$ (67,917)	$ 141,297	$ (81,447)
Monetization of crude oil puts and swaps	-	1,074,361	-
Natural gas derivatives	37,996	308,146	47,163
	$ (29,921)	$ 1,523,804	$ (34,284)

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.

Contingent Features

As of December 31, 2010, the counterparties to our commodity derivative contracts consist of nine 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 cross default and acceleration provisions relative to our material debt agreements. If we were to default on any of our material debt agreements, it would be a violation of these provisions, and the counterparties to our derivative agreements could request immediate payment on derivative instruments that are in a net liability position at that time. As of December 31, 2010, we were in a net liability position with all nine of the counterparties to our derivative instruments, totaling $77.7 million.

Note 6 — Investment

At December 31, 2010, we owned 51.0 million shares of McMoRan common stock, or an approximate 32.4% of their common shares outstanding. McMoRan is a publicly-traded oil and gas exploration and production company (New York Stock Exchange listing MMR) engaged in the exploration, development and production of natural gas and oil in the United States, specifically offshore in the shallow waters of the Gulf of Mexico Shelf and onshore in the Gulf Coast area. We acquired the McMoRan common stock and other consideration in exchange for all of our interests in our Gulf of Mexico leasehold located in less than 500 feet of water. See Note 3 – Divestments.

As contemplated by the Agreement and Plan of Merger, we and McMoRan entered into a registration rights agreement and a stockholder agreement at the closing of the transaction. Under the terms of the registration rights agreement, McMoRan is obligated to file a registration statement covering the McMoRan shares within 60 days after closing. The registration rights agreement also gives us piggyback registration rights and demand registration rights under certain circumstances. Under the terms of the stockholder agreement, McMoRan has expanded its board of directors and we have the right to designate two board members for so long as we own at least 10% of the outstanding shares of McMoRan. If our ownership falls below 10%, but is at least 5%, we will have the right to designate one director. The stockholder agreement requires us to refrain from certain activities that could be undertaken to acquire control of McMoRan and from transferring any McMoRan shares for one year after closing (subject to certain exceptions). After one year, we may sell shares of McMoRan common stock pursuant to underwritten offerings, in periodic sales under a shelf registration statement to be filed by McMoRan (subject to certain volume limitations), pursuant to the exercise of piggyback registration rights or as otherwise permitted by applicable law.

We are deemed to exercise significant influence over the operating and investing policies of McMoRan but do not have control. We have elected to measure our equity investment in McMoRan at fair value, and the change in fair value of our investment is included in our income statement. We believe that using fair value as a measurement basis for our investment is useful to our investors because our earnings on the investment will be dependent on the fair value on the date we divest the shares. At December 31, 2010, the McMoRan shares were valued at approximately $664.3 million, based on McMoRan's closing stock price of $17.14 on December 31, 2010 discounted to reflect certain restrictions on the marketability of the McMoRan shares.

McMoRan follows the successful efforts method of accounting for its oil and natural gas activities. Under this method of accounting, all costs associated with oil and gas lease acquisition, successful exploratory wells and all development wells are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves on a field basis. Unproved leasehold costs are capitalized pending the results of exploration efforts. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense when incurred. Below is summarized financial information of our proportionate share of McMoRan's financial position (in thousands):

	December 31, 2010 (1)
Financial Position	
Current assets	$ 339,176
Noncurrent assets	600,217
Current liabilities	135,511
Noncurrent liabilities	245,198
Net assets	$ 558,684

(1) Amounts represent our 32.4% equity ownership in McMoRan. We completed the divestment of our Gulf of Mexico shallow water properties on December 30, 2010. Our proportionate share of McMoRan's 2010 results of operations is not presented because it is insignificant as PXP owned the investment for one day and it is not practicable to determine one day's results of operations.

Note 7 — 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 and investment are recorded at fair value on a recurring basis in our balance sheet with the changes in fair value recorded in our income statement. The following table presents, for each fair value hierarchy level, our commodity derivative assets and liabilities and our investment measured at fair value on a recurring basis as of December 31, 2010 and 2009 (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)**
2010				
Commodity derivative contracts:				
Crude oil puts	$ 88,176	$ -	$ 88,176	$ -
Crude oil collars	(317)	-	(317)	-
Natural gas collars	(10,469)	-	-	(10,469)
Natural gas puts	15,254	-	-	15,254
Investment (2)	664,346	-	-	664,346
	$ 756,990	$ -	$ 87,859	$ 669,131
2009				
Commodity derivative contracts:				
Crude oil puts	$ 15,173	$ -	$ 15,173	$ -
Natural gas collars	14,312	-	-	14,312
	$ 29,485	$ -	$ 15,173	$ 14,312

(1) Option premium and accrued interest of $164.2 million and $73.3 million in 2010 and 2009, respectively, and settlement payable of $6.2 million and $3.4 million in 2010 and 2009, respectively, are not included in the fair value of derivatives.
(2) Represents our equity investment in McMoRan which would otherwise be reported under the equity method of accounting.

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 counterparties' 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 counterparties' 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, 2010, our crude oil put options and crude oil collars are classified as Level 2 and our natural gas put options and natural gas collars are classified as Level 3 instruments.

We determine the fair value of our investment by applying a discount for lack of marketability at the reporting date. The discount factor for lack of marketability is determined by utilizing both Protective put and Asian put option models. Both of these options are valued using a Black-Scholes option-pricing model which utilizes various inputs including the closing price of the McMoRan common stock, term of the restrictions, historical and implied volatility of the instrument, size of the holding being valued, length of time that would be necessary to dispose of our investment, expected dividend and risk-free interest rates. As of December 31, 2010, we have classified our investment as Level 3 since the fair value is determined by utilizing significant inputs that are unobservable.

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, 2010 and 2009 (in thousands):

	Year Ended December 31,		
	2010 (1)		2009 (1)
	Commodity Derivatives	Investment	Commodity Derivatives
Fair value at beginning of period	$ 14,312	$ -	$ 1,790,718
Transfers (2)	-	-	(124,690)
Purchases	16,894	665,897	1,038
Realized and unrealized gains (losses) included in earnings (3)	12,613	(1,551)	226,186
Settlements	(39,034)	-	(1,878,940)
Fair value at end of period	$ 4,785	$ 664,346	$ 14,312
Change in unrealized (losses) and gains relating to assets and liabilities held as of the end of the period (3)	$ (12,108)	$ (1,551)	$ 13,274

(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.
(3) Realized and unrealized gains included in earnings for the period are reported as a (loss) gain on mark-to-market derivative contracts and other income (expense) in our income statement for our commodity derivative contracts and our investment, respectively.

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 balance sheet.

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 balance sheet are stated at fair value; however, certain of our derivative financial instruments have a deferred premium, including our crude oil put options, crude oil collars and natural gas put options. The deferred premium reduces the asset or increases the liability depending on the fair value of the derivative financial instrument.

The following table presents the carrying amounts and fair values of our other financial instruments as of December 31, 2010 and 2009 (in thousands):

	December 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Current Liability				
Deferred premium and accrued interest on derivative contracts	$ 59,895	$ 59,895	$ 73,305	$ 73,305
Non-Current Liability				
Deferred premium and accrued interest on derivative contracts	104,260	104,260	-	-
Long-Term Debt				
Senior revolving credit facility	620,000	620,000	230,000	230,000
7¾% Senior Notes	600,000	625,500	600,000	610,500
10% Senior Notes	530,812	631,388	526,222	618,675
7% Senior Notes	500,000	513,750	500,000	491,250
7⅝% Senior Notes	400,000	421,000	400,000	409,000
8⅝% Senior Notes	393,905	438,000	393,467	411,000
7⅝% Senior Notes	300,000	316,125	-	-

The carrying value of our senior revolving credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates. The fair value of our Senior Notes is based on quoted market prices from trades of such debt.

Note 8 — Asset Retirement Obligation

The following table reflects the changes in our asset retirement obligation during the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Asset retirement obligation - beginning of period	$ 221,367	$ 169,809	$ 195,408
Liabilities incurred in acquisitions	246	-	1,697
Property dispositions and other	(7,883)	-	(29,236)
Settlements	(3,718)	(3,699)	(6,907)
Change in estimate	6,179	39,518	(7,571)
Accretion expense	17,702	14,332	13,036
Asset retirement additions	5,539	1,407	3,382
Asset retirement obligation - end of period (1)	$ 239,432	$ 221,367	$ 169,809

(1) $13.9 million and $7.1 million are included in other current liabilities at December 31, 2010 and 2009, 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 9 — Stock-Based and Other Compensation Plans

We have four 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; the 2006 Incentive Plan, or the 2006 Plan, which provides for a maximum of 5.0 million shares available for awards; and the 2010 Incentive Award Plan, or the 2010 Plan, which provides for a maximum of 5.0 million shares available for awards. Our 2002 Plan, 2004 Plan and 2010 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 ten 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 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, 2010, 2009 and 2008 was (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Stock-based compensation included in			
General and administrative expense	$ 46,953	$ 56,098	$ 51,262
Lease operating expenses	3,922	4,392	(861)
Oil and natural gas properties under full cost method	14,662	15,930	11,465
Total stock-based compensation	$ 65,537	$ 76,420	$ 61,866

Stock-based compensation charged to earnings for the years ended December 31, 2010, 2009 and 2008 was (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Charged to earnings	$ 50,875	$ 60,490	$ 50,401
Tax benefit	(19,068)	(22,714)	(18,933)
	$ 31,807	$ 37,776	$ 31,468

At December 31, 2010, there was $163.2 million of total unrecognized compensation cost related to unvested stock-based compensation arrangements that is expected to be recognized over a weighted-average period of approximately 4.2 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, 2010 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, 2010	2,773	$ 38.90		
Granted	880	31.37		
Exercised	(117)	28.22		
Forfeited or expired	(380)	38.15		
Outstanding at December 31, 2010	3,156	37.29	$ 9,343	2.6
Exercisable at December 31, 2010	1,191	45.74	$ 1,162	1.4

The total intrinsic value of SARs exercised during the years ended December 31, 2010, 2009 and 2008 was $0.6 million, $0.4 million and $59.1 million, respectively. The weighted average grant date fair value per share for SARs granted in 2010, 2009 and 2008 was $11.08, $6.44 and $13.48, respectively.

We estimate the fair value of SARs granted using the Black-Scholes valuation model. The following assumptions are as of December 31, 2010, 2009 and 2008:

	2010	2009	2008
Expected life (in years)	1 - 4	1 - 4	1 - 4
Volatility	45.3% - 56.3%	41.7% - 78.1%	36.5% - 90.9%
Risk-free interest rate	0.3% - 1.5%	0.5% - 2.2%	0.4% - 1.3%
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, 2010 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, 2010	4,147	$ 38.36		
Granted	1,612	31.23		
Vested	(1,074)	29.24		
Vested and deferred	(348)	27.42		
Forfeited	(133)	29.94		
Reclassified from liability instruments	2,102	49.80		
Nonvested at December 31, 2010	6,306	40.50	$ 202,653	4.3

	Liability Instruments (thousands)	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value ($ thousands)	Average Remaining Contractual Life (years)
Nonvested at January 1, 2010	2,102	$ 49.80		
Reclassified to equity instruments	(2,102)	49.80		
Nonvested at December 31, 2010	-	-	$ -	-

The total intrinsic value of restricted stock and RSUs vested in 2010, 2009 and 2008 was $41.0 million, $24.6 million and $42.7 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, 2009 and 2008 was $22.27 per share and $52.31 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 nonvested shares in the tables above include 2.1 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 2011 through 2015 but payment of vested RSUs will be generally deferred until September 30, 2015, subject to certain exceptions. At December 31, 2010, 1.2 million nonvested shares had been granted and 0.9 million nonvested shares will be granted in 2011 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, until such time that the number of available shares is increased to a sufficient level to satisfy such awards, at which point the awards are reclassified back to equity awards.

Stock Options

At December 31, 2010, there were 13,234 stock options outstanding with an average exercise price of $8.21 per share and an average remaining life of 1.2 years. The intrinsic value of options exercised in the years ended December 31, 2010, 2009 and 2008 was $0.4 million, $0.1 million and $0.5 million, respectively, and we received $0.2 million, $0.1 million and $0.3 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 2010, 2009 and 2008 we made cash contributions totaling $9.2 million, $9.3 million and $7.0 million, respectively, to the 401(k) plan.

We have certain awards which have vested, but the issuance of those common shares has been deferred. During 2010, 2009 and 2008, approximately 348,000, 163,000 and 123,000 common shares, respectively, vested and were deferred resulting in a total of approximately 728,000 deferred common shares at December 31, 2010. These common shares will be issued upon the earliest of the deferral date, their retirement or death.

Note 10 — Income Taxes

For the years ended December 31, 2010, 2009 and 2008 our income (loss) before income taxes consisted of (in thousands):

	Year Ended December 31,		
	2010	2009	2008
U.S.	$ 263,917	$ 218,422	$ (1,147,367)
Non U.S.	(59,907)	(1,242)	(6,262)
	$ 204,010	$ 217,180	$ (1,153,629)

For the years ended December 31, 2010, 2009 and 2008 our income tax expense (benefit) consisted of (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Current			
U.S. Federal	$ (89,680)	$ 40,548	$ 195,154
State	(3,410)	4,543	35,661
	$ (93,090)	$ 45,091	$ 230,815
Deferred			
U.S. Federal	$ 180,384	$ 36,530	$ (613,768)
State	13,451	(746)	(61,582)
	193,835	35,784	(675,350)
	$ 100,745	$ 80,875	$ (444,535)

Our deferred income tax assets and liabilities at December 31, 2010 and 2009 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,	
	2010	2009
Deferred tax assets		
Net operating loss	$ 70,746	$ 85,070
Tax credits	53,265	97,681
Commodity derivative contracts and other	82,005	47,901
Oil and gas acquisition, exploration and development operations	223,909	
	429,925	230,652
Deferred tax liabilities		
Commodity derivative contracts	-	(172,376)
Net oil and gas acquisition, exploration and development operations and other	(1,710,889)	(1,145,497)
Net deferred tax liability	$ (1,280,964)	$ (1,087,221)
Current asset (liability)	$ 74,086	$ (153,473)
Long-term liability	(1,355,050)	(933,748)
	$ (1,280,964)	$ (1,087,221)

Tax carryforwards at December 31, 2010, which are available for future utilization on income tax returns, are as follows (in thousands):

FEDERAL	Amount	Expiration
Alternative minimum tax (AMT) credit	$ 4,250	-
Enhanced oil recovery credit	35,923	2025
Net operating loss - regular tax	45,310	2027
STATE		
Alternative minimum tax (AMT) credit	$ 521	-
Enhanced oil recovery credit	22,901	2016 - 2020
Net operating loss - regular tax	1,030,138	2021 - 2031

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 income statement (in thousands):

	Year Ended December 31,		
	2010	2009	2008
U.S. federal income tax provision (benefit) at statutory rate	$ 71,404	$ 76,013	$ (403,770)
State income taxes, net of federal expense (benefit)	10,041	1,025	(59,516)
Non-deductible expenses	14,644	15,839	14,066
Uncertain tax positions	(1,169)	(18,154)	21,403
Non-cash compensation	2,506	4,776	-
Other	3,319	1,376	(16,718)
Income tax expense (benefit) on income (loss) before income taxes	$ 100,745	$ 80,875	$ (444,535)

Tax Loss and Credit Carryovers. Certain of our U.S. tax loss and credit carryovers obtained as a result of the acquisitions of Nuevo Energy Company, or Nuevo, and Pogo are subject to IRC 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 2008 related to non-cash employee compensation which vested in that year 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 2010 and 2009 we recorded tax expense of $2.7 million and $5.1 million, respectively, related to non-cash employee compensation that vested in those years.

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

	2010	2009	2008
Balance at beginning of period	$ 16,473	$ 47,163	$ 24,370
Additions for tax positions in prior years	-	3,085	20,929
Reductions for tax positions of prior years	-	-	(538)
Additions based on tax positions related to the current year	-	-	2,402
Adjustments for audit settlements in the current year	(1,901)	(33,775)	-
Adjustments due to any expiration of a statute of limitations	(676)	-	-
Balance at end of period	$ 13,896	$ 16,473	$ 47,163

During 2008, we increased the balance of our gross unrecognized tax benefits by $22.8 million primarily related to certain tax credits for tax years under audit. During 2009, we received revenue agent reports from the IRS relating to these tax years. As a result of these reports, we reduced our balance of gross unrecognized tax benefits by $30.7 million primarily related to certain tax credits. During 2010, we concluded our administrative appeal with the IRS and as a result reduced our balance of gross unrecognized tax benefits by $2.6 million primarily related to certain tax deductions for these same tax years.

We estimate our balance of net unrecognized tax benefits will be reduced by $6.0 million to $8.0 million over the next twelve months as the statute of limitations expires for various tax years. Included in the balance at December 31, 2010 is approximately $13.0 million that would affect our effective tax rate if recognized. The difference between this amount and the $13.9 million ending balance of gross unrecognized tax benefits represents 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 $3.1 million and $2.2 million of accrued interest on unrecognized tax benefits in our balance sheets as of December 31, 2010 and 2009, respectively. We did not have any accrued liabilities for penalties related to unrecognized tax benefits for the years ended December 31, 2010 and 2009.

We file income tax returns in the U.S. federal and various state and foreign jurisdictions. In 2010, we concluded our administrative appeal with the IRS related to its examination of ours and Nuevo's 2003 and 2004 income tax returns and have reflected the results in our 2010 financial statements. As of December 31, 2010, we are not under examination by the IRS and are no longer subject to U.S. federal income tax examinations for years prior to 2007 except for certain tax credit carryforwards generated before 2007, but utilized after 2006.

In December 2010, the state of California commenced an audit of our 2008 California income tax return. As of December 31, 2010, we were not under examination in any state income tax jurisdictions except for California. In all states except California, we are no longer subject to state income tax examinations by the relevant tax authorities for years prior to 2007. For California, we are no longer subject to state income tax examinations for years prior to 2006 except for certain tax loss and credit carryforwards generated before 2006 but utilized after 2005.

Note 11 — 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):

2011	$ 18,352
2012	14,451
2013	14,015
2014	11,551
2015	10,941
Thereafter	21,910
	$ 91,220

Total expenses related to such leases were $12.3 million, $13.0 million and $10.8 million in 2010, 2009 and 2008, respectively.

Drilling Contracts. We are committed to drilling obligations with certain rig contractors with terms from one year up to three years and future commitments of $34.7 million in 2011, $19.4 million in 2012, $17.9 million in 2013 and $2.8 million in 2014 primarily to perform our Eagle Ford Shale drilling program.

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 have received an indemnity with respect to those costs. We cannot be assured that we will be able to collect on these indemnities.

We estimate our 2011 cash expenditures related to plugging, abandonment and remediation will be approximately $13.9 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, $70.1 million ($144.1 million undiscounted), is included in our asset retirement obligation as reflected in our 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 $75.0 million). To secure its abandonment obligations, the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2010, the escrow account had a balance of $14.7 million. The fair value of our guarantee at December 31, 2010, $0.3 million, considers the payment/performance risk of the purchaser and is included in other long-term liabilities in our 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. 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. 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 are self-insured for named windstorms in the Gulf of Mexico. 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. 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 these commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

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.

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 2010, 2009 and 2008, sales to ConocoPhillips accounted for 57%, 44% and 36%, respectively, of our total revenues. During 2009 and 2008, sales to Plains Marketing, L.P., or PMLP, accounted for 22% and 23%, respectively, of our total revenues. The contract with PMLP expired in

November 2009, and we entered into contracts with purchasers who previously purchased through PMLP, the most significant of which was ConocoPhillips. During 2010, 2009 and 2008, no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect; however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, their role as the purchaser of a significant portion of our oil production does have the potential to impact our overall exposure to credit risk, either positively or negatively, in that they may be affected by changes in economic, industry or other conditions. We generally do not require letters of credit or other collateral from 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 12 — Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2010	2009	2008
Cash payments for interest (net of capitalized interest)	$ 98,262	$ 45,496	$ 117,278
Cash (receipts) payments for income taxes	$ (58,920)	$ 151,682	$ 127,428

At December 31, 2010 and 2009, accrued capital expenditures included in accounts payable in the balance sheet were $150.1 million and $135.2 million, respectively.

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

	Year Ended December 31,		
	2010	2009	2008
Shares (1)	728	765	508
Amount (1)	$ 21,232	$ 15,498	$ 27,512

(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 reductions and additions included:

- non-cash reductions to oil and gas properties of $665.9 million related to the sale of our Gulf of Mexico shallow water shelf properties in exchange for 51.0 million shares of McMoRan common stock;
- acquisition of acreage in the Piceance Basin 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; and

- non-cash additions to oil and gas properties of $21.8 million and $55.3 million in 2010 and 2009, respectively, and reductions to oil and gas properties of $18.7 million in 2008 related to our asset retirement obligation.

Our crude oil put options, crude oil collars and natural gas put options include deferred premiums to be paid to the counterparty based on the settlement terms specified in the contract. During 2010, 2009 and 2008, we entered into derivative contracts with deferred premiums of $162.9 million, $74.1 million and $313.6 million, respectively.

Note 13 — Stockholders' Equity

Earnings Per Share

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

	Year Ended December 31,		
	2010	2009	2008
Common shares outstanding - basic	140,438	124,405	108,828
Unvested restricted stock, restricted stock units and stock options	1,459	883	-
Common shares outstanding - diluted	141,897	125,288	108,828

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. For the years ended December 31, 2010 and 2009, 1.8 million and 2.4 million, respectively, restricted stock units 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, 2010 is 250.0 million, with a par value of $0.01.

The number of authorized preferred shares at December 31, 2010 is 5.0 million, with a par value of $0.01. No preferred shares were issued as of December 31, 2010.

Stock Repurchase Program

Our Board of Directors has authorized the repurchase of shares 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. We currently have $695.8 million in authorized repurchases remaining under the program.

Note 14 — Other Operating (Income) Expense and Other Income (Expense)

Other operating income for 2010 primarily consists of production tax abatements related to production in prior years. 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.

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

	December 31,		
	2010	2009	2008
Royalty receipts and related interest [1]	$ 8,121	$ 23,501	$ -
Preacquisition adjustments [1]	4,998	3,203	(16,547)
Equity income in partnership	-	-	947
Loss on investment measured at fair value	(1,551)	-	-
Other	2,823	1,264	3,025
	$ 14,391	$ 27,968	$ (12,575)

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

Note 15 — 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 $7^5/_8$% Senior Notes due 2018, $400 million of $8^5/_8$% Senior Notes and $300 million of $7^5/_8$% Senior Notes due 2020 as of December 31, 2010, 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, 2010
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 6,020	$ 8	$ 406	$ -	$ 6,434
Accounts receivable and other current assets	256,561	133,761	6,131	-	396,453
	262,581	133,769	6,537	-	402,887
Property and Equipment, at cost					
Oil and natural gas properties - full cost method	3,878,473	8,721,483	679,654	-	13,279,610
Other property and equipment	49,110	41,736	46,304	-	137,150
	3,927,583	8,763,219	725,958	-	13,416,760
Less allowance for depreciation, depletion, amortization and impairment	(2,420,233)	(5,769,846)	(62,262)	2,056,333	(6,196,008)
	1,507,350	2,993,373	663,696	2,056,333	7,220,752
Investment in and Advances to Affiliates	5,088,866	(1,562,441)	(665,455)	(2,860,970)	-
Other Assets	726,277	545,021	-	-	1,271,298
	$ 7,585,074	$ 2,109,722	$ 4,778	$ (804,637)	$ 8,894,937
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities	$ 362,741	$ 147,246	$ 23,702	$ -	$ 533,689
Long-Term Debt	3,344,717	-	-	-	3,344,717
Other Long-Term Liabilities	216,426	61,761	329	-	278,516
Deferred Income Taxes	278,225	323,829	(1,753)	754,749	1,355,050
Stockholders' Equity	3,382,965	1,576,886	(17,500)	(1,559,386)	3,382,965
	$ 7,585,074	$ 2,109,722	$ 4,778	$ (804,637)	$ 8,894,937

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 STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2010
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 947,552	$ 190,046	$ 5,162	$ -	$ 1,142,760
Gas sales	67,578	331,827	202	-	399,607
Other operating revenues	884	1,344	-	-	2,228
	1,016,014	523,217	5,364	-	1,544,595
Costs and Expenses					
Production costs	295,611	155,617	674	-	451,902
General and administrative	87,743	48,322	372	-	136,437
Depreciation, depletion, amortization and accretion	234,660	161,006	2,749	152,703	551,118
Impairment of oil and gas properties	-	266,442	59,475	(266,442)	59,475
Legal recovery	-	(8,423)	-	-	(8,423)
Other operating income	(988)	(3,142)	-	-	(4,130)
	617,026	619,822	63,270	(113,739)	1,186,379
Income (Loss) from Operations	398,988	(96,605)	(57,906)	113,739	358,216
Other (Expense) Income					
Equity in earnings of subsidiaries	(104,430)	(68)	-	104,498	-
Interest expense	(84)	(104,383)	(2,246)	-	(106,713)
Debt extinguishment costs	(1,189)	-	-	-	(1,189)
Loss on mark-to-market derivative contracts	(60,695)	-	-	-	(60,695)
Other income (expense)	976	13,486	(71)	-	14,391
Income (Loss) Before Income Taxes	233,566	(187,570)	(60,223)	218,237	204,010
Income tax (expense) benefit	(130,301)	50,995	3,270	(24,709)	(100,745)
Net Income (Loss)	$ 103,265	$ (136,575)	$ (56,953)	$ 193,528	$ 103,265

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 (Expense) Income					
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 CASH FLOWS
YEAR ENDED DECEMBER 31, 2010
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 103,265	$ (136,575)	$ (56,953)	$ 193,528	$ 103,265
Items not affecting cash flows from operating activities					
Depreciation, depletion, amortization, accretion and impairment	234,660	427,448	62,224	(113,739)	610,593
Equity in earnings of subsidiaries	104,430	68	-	(104,498)	-
Deferred income tax (benefit) expense	(298,084)	469,426	(3,324)	25,817	193,835
Debt extinguishment costs	1,189	-	-	-	1,189
Loss on mark-to-market derivative contracts	60,695	-	-	-	60,695
Non-cash compensation	39,114	11,761	-	-	50,875
Other non-cash items	4,286	(1,890)	198	-	2,594
Change in assets and liabilities from operating activities					
Accounts receivable and other assets	(18,290)	(23,356)	(4,460)	-	(46,106)
Accounts payable and other liabilities	10,120	(42,229)	2,260	(1,502)	(31,351)
Income taxes receivable/payable	(33,119)	-	-	-	(33,119)
Net cash provided by (used in) operating activities	208,266	704,653	(55)	(394)	912,470
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(356,286)	(679,918)	(12,654)	-	(1,048,858)
Acquisition of oil and gas properties	(291)	35,431	(589,825)	-	(554,685)
Proceeds from sales of oil and gas properties	73,845	120	-	-	73,965
Derivative settlements	(29,921)	-	-	-	(29,921)
Additions to other property and equipment	(4,007)	(6,115)	(5,687)	-	(15,809)
Net cash used in investing activities	(316,660)	(650,482)	(608,166)	-	(1,575,308)
CASH FLOWS FROM FINANCING ACTIVITIES					
Borrowings from revolving credit facilities	3,332,610	-	-	-	3,332,610
Repayments of revolving credit facilities	(2,942,610)	-	-	-	(2,942,610)
Proceeds from issuance of Senior Notes	300,000	-	-	-	300,000
Costs incurred in connection with financing arrangements	(22,771)	-	-	-	(22,771)
Investment in and advances to affiliates	(554,303)	(54,174)	608,083	394	-
Other	184	-	-	-	184
Net cash provided by (used in) financing activities	113,110	(54,174)	608,083	394	667,413
Net increase (decrease) in cash and cash equivalents	4,716	(3)	(138)	-	4,575
Cash and cash equivalents, beginning of period	1,304	11	544	-	1,859
Cash and cash equivalents, end of period	$ 6,020	$ 8	$ 406	$ -	$ 6,434

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
Non-cash compensation	49,037	11,453	-	-	60,490
Other non-cash 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	(12,208)	(35,007)	109	-	(47,106)
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)
Non-cash compensation	43,240	7,197	(36)	-	50,401
Other non-cash 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

Note 16 — Quarterly Financial Data (Unaudited)

The following table shows summary financial data for 2010 and 2009 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2010					
Revenues	$ 384,050	$ 364,593	$ 387,823	$ 408,129	$ 1,544,595
Income from operations	118,782	49,797	97,085	92,552	358,216
Net income (loss)	58,528	45,375	18,848	(19,486)	103,265
Basic earnings per share	0.42	0.32	0.13	(0.14)	0.74
Diluted earnings per share	0.41	0.32	0.13	(0.14)	0.73
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

Note 17 — Oil and Natural Gas Activities

In December 2009, we adopted the SEC's final rule, Modernization of Oil and Gas Reporting, which was first effective for reporting 2009 reserve information and revised oil and gas reserve estimation and disclosure requirements. We are required to use the twelve-month average of the first-day-of-the-month reference prices compared to the year-end reference prices, in each case adjusted for location and quality differentials, when estimating reserve quantities. 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. The impact of the adoption of the SEC final rule on our financial statements was 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.

Investment

At December 31, 2010, we owned 51.0 million shares of McMoRan common stock or an approximate 32.4% of their common shares outstanding. McMoRan is a publicly-traded oil and gas exploration and production company (New York Stock Exchange listing MMR) engaged in the exploration, development and production of natural gas and oil in the United States, specifically offshore in the shallow waters of the Gulf of Mexico Shelf and onshore in the Gulf Coast area. We acquired the McMoRan common stock and other consideration in exchange for all of our interests in our Gulf of Mexico leasehold located in less than 500 feet of water. See Note 3 – Divestments.

McMoRan follows the successful efforts method of accounting for its oil and natural gas activities. See Note 6 – Investment.

Costs Incurred

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

	Year Ended December 31,		
	2010 (1)	2009	2008
Consolidated entities			
Property acquisition costs			
Unproved properties	$ 612,471	$ 1,121,644	$ 1,878,842
Proved properties	48,078	5,072	267,161
Exploration costs	719,004	1,309,396	520,612
Development costs	363,242	272,820	576,753
	$ 1,742,795	$ 2,708,932	$ 3,243,368

(1) We completed the divestment of our Gulf of Mexico shallow water properties on December 30, 2010. Our proportionate share of McMoRan's 2010 costs incurred is not presented because it is insignificant as PXP owned the investment for one day and it is not practicable to determine one day of costs incurred.

Amounts presented include capitalized general and administrative expense of $68.0 million, $67.3 million and $60.6 million in 2010, 2009 and 2008, respectively, and capitalized interest expense of $128.0 million, $113.8 million and $70.5 million in 2010, 2009 and 2008, respectively. Our international exploration costs, primarily in offshore Vietnam, were $1.7 million, $42.3 million and $4.5 million in 2010, 2009 and 2008, respectively.

In the second quarter of 2010, we completed our interpretation of seismic and drilling data from our two offshore Vietnam exploratory wells and decided not to pursue additional exploratory activities in this area. We have submitted a notice to the Vietnam state oil company in order to terminate our production sharing contract in accordance with its terms. The costs related to our Vietnam oil and gas properties were transferred to our Vietnam full cost pool where they were subject to the ceiling limitation. Because our Vietnam full cost pool had no associated proved oil and gas reserves, we recorded a non-cash pre-tax impairment charge of $59.5 million. We also recorded a corresponding tax benefit of $23.0 million.

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,	
	2010	2009
Consolidated entities		
Property subject to amortization	$ 9,975,056	$ 9,044,146
Accumulated DD&A and impairment	(6,176,007)	(5,598,995)
	$ 3,799,049	$ 3,445,151
Entity's share of equity investee (1)		
Unproved properties	$ 341,625	
Proved properties	789,584	
Accumulated DD&A and impairment	(552,682)	
	$ 578,527	

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010.

Our average DD&A rate per BOE was $15.87, $12.79 and $17.69 (excluding impairment charges) in 2010, 2009 and 2008, respectively.

Costs not subject to amortization

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

	December 31,				
	Total	**2010**	**2009 (1)**	**2008 (2)**	**Prior**
Acquisition costs	$ 2,562,134	$ 721,158	$ 1,020,731	$ 668,381	$ 151,864
Exploration costs	517,403	71,047	215,886	158,515	71,955
Capitalized interest	225,017	121,673	83,023	11,646	8,675
	$ 3,304,554	$ 913,878	$ 1,319,640	$ 838,542	$ 232,494

(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 costs 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 60% of the costs not subject to amortization at December 31, 2010 will be transferred to the amortization base over the next five years and the remainder in the next seven to ten years.

Approximately 41% of our total net undeveloped acreage is covered by leases that will expire from 2011 through 2013. In 2008 and 2010, we added a significant number of new leases in the Haynesville Shale and the Eagle Ford Shale, respectively, with lease terms generally ranging from two to three years; however, we are participating in the drilling of wells in these areas to establish production in order to hold a majority of the acreage beyond lease expiration. Approximately 73% of the total exploration costs 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 or the properties are divested.

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,		
	2010 (1)	2009	2008
Revenues from oil and gas producing activities	$ 1,544,595	$ 1,187,130	$ 2,403,471
Production costs	(447,772)	(426,103)	(626,428)
Depreciation, depletion, amortization and accretion	(535,239)	(405,597)	(605,440)
Impairment of oil and gas properties	(59,475)	-	(3,629,666)
Income tax (expense) benefit	(188,190)	(133,464)	923,003
Results of operations from producing activities for consolidated entities (excluding general and administrative and interest costs)	$ 313,919	$ 221,966	$ (1,535,060)

(1) We completed the divestment of our Gulf of Mexico shallow water properties on December 30, 2010. Our proportionate share of McMoRan's 2010 results of operations is not presented because it is insignificant as PXP owned the investment for one day and it is not practicable to determine one day's results of operations.

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, 2010. All of our reserves are located in the United States. In 2010 our reserves were based upon (1) reserve reports prepared by the independent petroleum engineers of Netherland, Sewell & Associates, Inc., or NSA, and Ryder Scott Company L.P., or Ryder Scott (99% of reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum engineer (1% of reserve volumes). In 2009, our reserves were based upon reserve reports prepared by NSA and Ryder Scott. In 2008, our reserves were based upon (1) reserve reports prepared by NSA 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).

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 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. 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 51% of our 2010 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, 2010.

	Oil (MBbl)	Gas (MMcf)	(MBOE)
2010			
Consolidated entities			
Proved Reserves			
Beginning balance	214,030	873,108	359,548
Revision of previous estimates	15,299	28,111	19,984
Extensions, discoveries and other additions	10,250	401,288	77,131
Improved recovery	-	-	-
Purchase of reserves in-place	1,260	854	1,403
Sale of reserves in-place	(802)	(51,244)	(9,343)
Production	(16,769)	(95,047)	(32,610)
Ending balance	223,268	1,157,070	416,113
Proved Developed Reserves, December 31	150,492	517,183	236,689
Proved Undeveloped Reserves, December 31	72,776	639,887	179,424
Entity's share of equity investee (1)			
Proved Reserves			
Beginning balance	5,028	57,938	14,684
Revision of previous estimates	204	3,859	847
Extensions, discoveries and other additions	-	-	-
Improved recovery	-	-	-
Purchase of reserves in-place	360	15,091	2,875
Sale of reserves in-place	(72)	(272)	(117)
Production	(804)	(14,248)	(3,178)
Ending balance	4,716	62,368	15,111
Proved Developed Reserves, December 31	4,315	46,974	12,144
Proved Undeveloped Reserves, December 31	401	15,394	2,967

Table continued on following page.

	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

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010.

Revisions of Previous Estimates

In 2010, we had positive revisions of 20 MMBOE. Positive revisions of 8 MMBOE were primarily related to higher realized oil prices principally at our California properties while positive revisions of 12 MMBOE were primarily related to higher realized gas prices principally at our Panhandle, Haynesville Shale and South Texas properties.

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.

Purchases of Reserves in-Place

In 2010, proved reserve additions acquired in the Eagle Ford Shale were 1 MMBOE.

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 in Colorado.

Extensions, Discoveries and Other Additions

In 2010, we had a total of 77 MMBOE of extensions and discoveries, including 54 MMBOE in the Haynesville Shale resulting from successful drilling during 2010 that extended and developed the proved acreage and 17 MMBOE of extensions and discoveries in the Panhandle resulting from successful horizontal development and extension of the proved acreage in the Granite/Atoka Wash.

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 our 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.

Sales of Reserves in-Place

In 2010, we had a total of 9 MMBOE of divestments, all of which were from our shallow water Gulf of Mexico divestment to McMoRan.

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,		
	2010	2009	2008
Consolidated entities			
Future cash inflows	$ 21,151,315	$ 14,623,292	$ 9,311,501
Future development costs	(3,290,657)	(2,371,383)	(1,704,350)
Future production expense	(7,919,772)	(6,187,933)	(4,345,314)
Future income tax expense	(3,197,758)	(1,521,281)	(772,225)
Future net cash flows	6,743,128	4,542,695	2,489,612
Discounted at 10% per year	(3,649,993)	(2,317,856)	(1,353,238)
Standardized measure of discounted future net cash flows	$ 3,093,135	$ 2,224,839	$ 1,136,374
Entity's share of equity investee (1)			
Future cash inflows	$ 656,020		
Future development costs	(192,889)		
Future production expense	(165,640)		
Future income tax expense	-		
Future net cash flows	297,491		
Discounted at 10% per year	(86,593)		
Standardized measure of discounted future net cash flows	$ 210,898		

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010.

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 2010 and 2009 are made using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Estimates for 2008 reflect previously disclosed amounts 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, 2010 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 sales prices used in the reserve reports as of December 31, 2010, 2009 and 2008 were $72.83, $54.38 and $31.75 per barrel of oil, respectively, and $4.29, $3.53 and $5.50 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, 2010, are as follows (in thousands):

	Year Ended December 31,		
	2010 (1)	2009	2008
Consolidated entities			
Balance, beginning of year	$ 2,224,839	$ 1,136,374	$ 7,623,323
Sales, net of production expenses	(1,090,465)	(761,157)	(1,760,135)
Net change in sales and transfer prices, net of production expenses	2,030,484	1,568,827	(7,161,276)
Extensions, discoveries and improved recovery, net of costs	410,973	87,890	389,719
Changes in estimated future development costs	(335,614)	(163,602)	1,013,179
Previously estimated development costs incurred during the year	267,719	144,017	369,693
Purchase of reserves in-place	41,214	3,198	201,771
Sale of reserves in-place	(120,082)	-	(2,503,747)
Revision of quantity estimates	338,683	443,344	(1,800,309)
Accretion of discount	273,259	188,134	812,356
Net change in income taxes	(947,875)	(422,186)	3,951,800
Balance, end of year	$ 3,093,135	$ 2,224,839	$ 1,136,374

(1) We completed the divestment of our Gulf of Mexico shallow water properties on December 30, 2010. Our proportionate share of McMoRan's 2010 changes in the standardized measure is not presented because it is insignificant as PXP owned the investment for one day and it is not practicable to determine one day's change in the standardized measure.

COMPANY INFORMATION

CORPORATE INFORMATION

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

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, 2010, is available free of charge on request to:

Investor Relations
Attn: Joanna Pankey
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EXECUTIVE OFFICERS

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Chairman, President and Chief Executive Officer

Doss R. Bourgeois
Executive Vice President – Exploration & Production

Winston M. Talbert
Executive Vice President and Chief Financial Officer

John F. Wombwell
Executive Vice President and General Counsel

DIRECTORS

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

Isaac Arnold, Jr.
President of The Arnold Corporation and
Former Chairman of Quintana Petroleum Corporation

Alan R. Buckwalter, III
Retired, Chairman and Chief Executive Officer
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Jerry L. Dees
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Vastar Resources, Inc.

Tom H. Delimitros
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Thomas A. Fry, III
Former President
National Ocean Industries Association

Charles G. Groat
Director, Center for International Energy and Environmental Policy and
The Energy and Earth Resources Graduate Program
The University of Texas at Austin

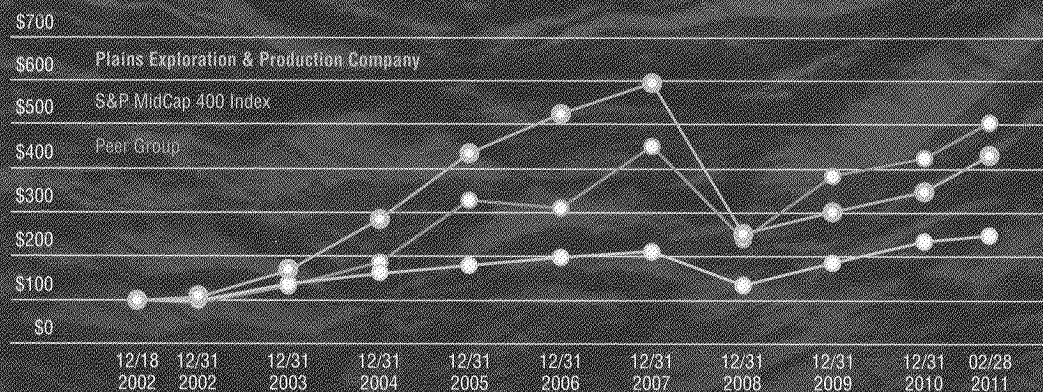
John H. Lollar
Managing Partner
Newgulf Exploration L.P.

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 December 18, 2002, the date we became a public company, through February 28, 2011, 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.



STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking information regarding Plains Exploration & Production Company ("PXP", the "Company", "us", "our" or "we") 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;
- the effects of future laws and governmental regulation that result from the Macondo accident and oil spill in the Gulf of Mexico;
- the value of the common stock of McMoRan Exploration Co. and our ability to dispose of those shares;
- the value and completion of the monetization of our Gulf of Mexico deepwater assets;
- 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 in this Annual Report.

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