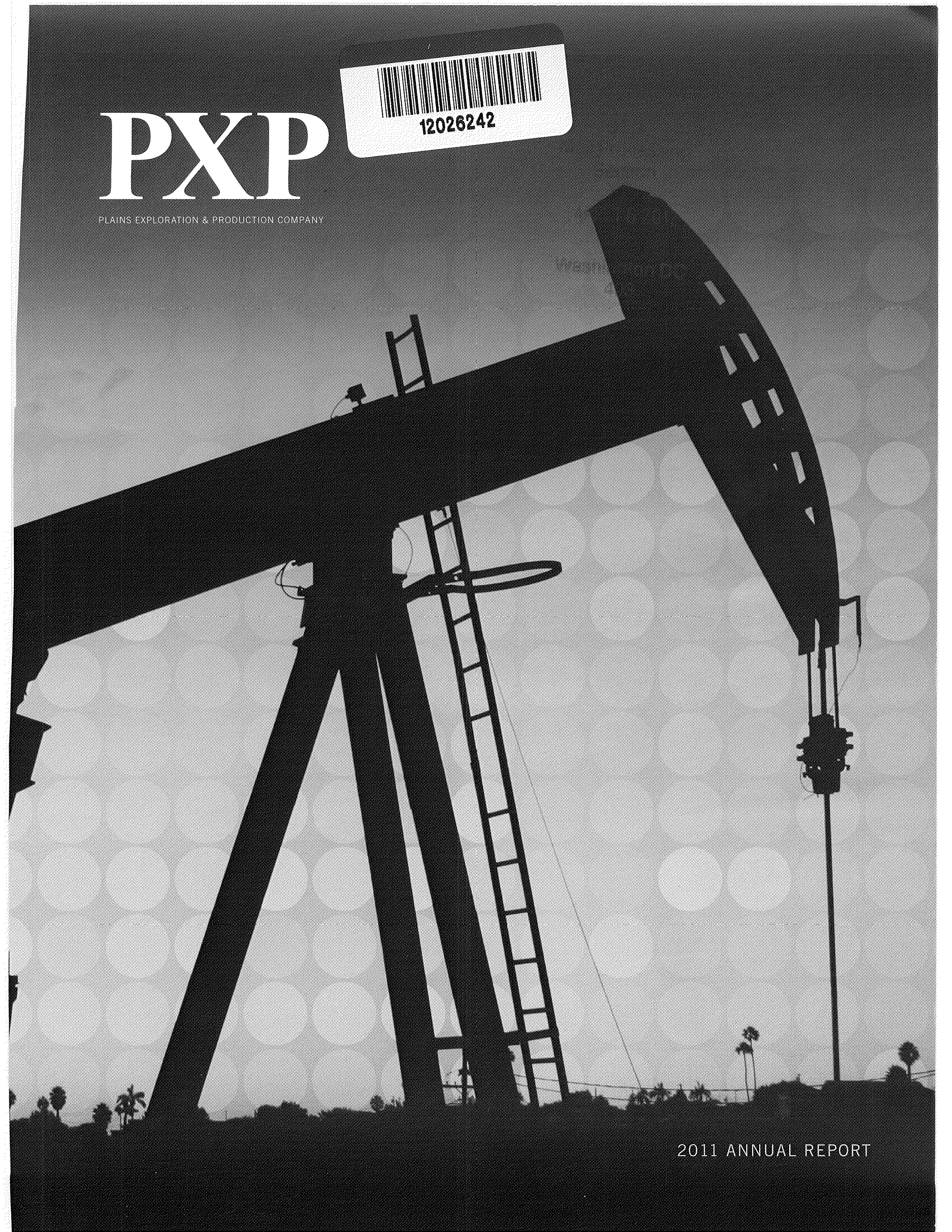


PXP

PLAINS EXPLORATION & PRODUCTION COMPANY

2011 ANNUAL REPORT

FINANCIAL HIGHLIGHTS

(in thousands, except per share and percentage information)	2011	2010	2009	2008	2007
Reserve Data:					
Total oil reserves (barrels)	244,030	223,268	214,030	177,707	436,533
Total gas reserves (Mcf)	1,001,311	1,157,070	873,108	686,357	1,519,976
Total barrels of oil equivalent (BOE)	410,915	416,113	359,548	292,100	689,862
Percentage proved developed volume	55%	57%	64%	72%	51%
Estimated future net cash flows	$ 10,942,358	$ 6,743,128	$ 4,542,695	$ 2,489,612	$ 18,042,121
Standardized measure	$ 5,134,181	$ 3,093,135	$ 2,224,839	$ 1,136,374	$ 7,623,323
Percentage proved developed present value	73%	77%	80%	96%	67%
Operating Data:					
Oil production (barrels)	17,872	16,769	17,560	20,294	18,124
Average oil price (per barrel)[1]	$ 85.53	$ 68.14	$ 51.43	$ 87.05	$ 61.60
Gas production (Mcf)	111,577	95,047	78,184	79,254	29,312
Average gas price (per Mcf)[1]	$ 3.91	$ 4.29	$ 3.72	$ 8.05	$ 5.68
BOE production	36,468	32,610	30,591	33,503	23,010
Average BOE price[1]	$ 54.18	$ 47.77	$ 39.25	$ 72.03	$ 56.12
Production expense per BOE	$ 15.47	$ 14.00	$ 14.03	$ 18.91	$ 18.25
Selected Financial Data:					
Total revenue	$ 1,964,488	$ 1,544,595	$ 1,187,130	$ 2,403,471	$ 1,272,840
Income (loss) from operations[2]	$ 590,549	$ 358,216	$ 282,133	$ (2,627,413)	$ 419,634
Net income (loss)	$ 206,679	$ 103,265	$ 136,305	$ (709,094)	$ 158,751
Net income attributable to noncontrolling interest in the form of preferred stock of subsidiary	$ (1,400)				
Net income (loss) attributable to common stockholders	$ 205,279	$ 103,265	$ 136,305	$ (709,094)	$ 158,751
Earnings (loss) per diluted common share	$ 1.44	$ 0.73	$ 1.09	$ (6.52)	$ 1.99
Weighted average common shares outstanding					
Basic	141,227	140,438	124,405	108,828	78,627
Diluted	142,999	141,897	125,288	108,828	79,808
Total assets	$ 9,791,472	$ 8,894,937	$ 7,734,731	$ 7,111,915	$ 9,693,351
Long-term debt	$ 3,760,952	$ 3,344,717	$ 2,649,689	$ 2,805,000	$ 3,305,000
Total stockholders' equity	$ 3,264,636	$ 3,382,965	$ 3,198,981	$ 2,377,280	$ 3,338,247
Noncontrolling interest – preferred stock of subsidiary	$ 430,596				
Total equity	$ 3,695,232	$ 3,382,965	$ 3,198,981	$ 2,377,280	$ 3,338,247

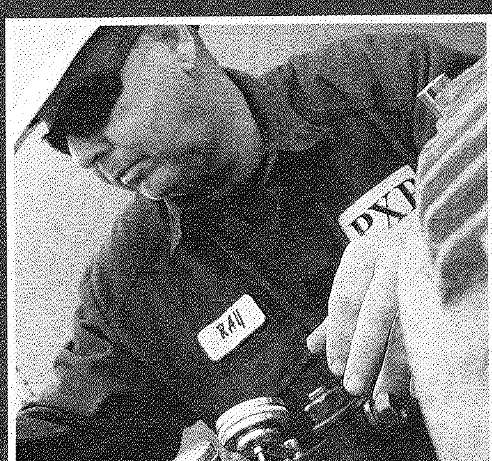
[1] *Average realized sales price before derivative transactions.*

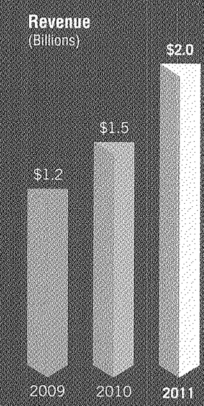
[2] *We are required to perform a full cost ceiling test each quarter. At December 31, 2008, our capitalized costs of oil and gas properties exceeded the ceiling, and we recorded a pre-tax non-cash impairment of oil and gas properties of $3.6 billion.*

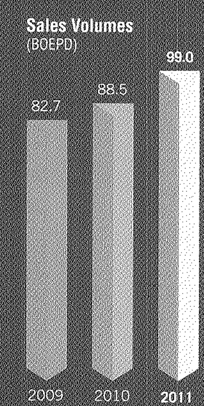
PXP is committed to providing a work place that protects the health and safety of our employees and the communities surrounding our operations, and to adhering to high standards of environmental quality.

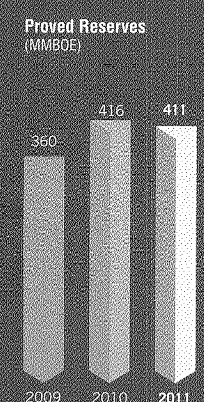
We strive to lead the industry not only in compliance, but in innovation that sets new standards. With an award-winning commitment to safety and environmental excellence, industry-leading operational expertise, and collaborative approach, PXP has achieved great success in challenging technical and regulatory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

PXP is building value by finding and producing oil and natural gas safely, reliably and efficiently.




Revenue
(Billions)
$1.2
$1.5
$2.0
2009
2010
2011


Sales Volumes
(BOEPD)
82.7
88.5
99.0
2009
2010
2011


Proved Reserves
(MMBOE)
360
416
411
2009
2010
2011

TO OUR SHAREHOLDERS

James C. Flores
Chairman, President and
Chief Executive Officer

With outstanding consecutive quarter-to-quarter production growth and excellent operating results, PXP had another exceptional year. We continued to implement our oil growth strategy, which resulted in a very busy year and put us in an excellent position to continue delivering impressive financial and operating results during a period that has proven to be a structurally strong oil market and a weak natural gas market. We secured financing for our premier Gulf of Mexico assets and responded to changing oil differentials, lower interest rates, and a weak gas market by renegotiating our oil marketing contracts, refinancing a portion of our long term debt and strengthening our hedging program.

Among the many accomplishments achieved for the year, our net income attributable to common stockholders was up nearly 100% compared to 2010, and PXP achieved record sales volumes. In addition, PXP delivered substantially higher proved reserve value, improved cash margins and solid reserve additions. These attributes are the building blocks for sustained value creation and align with our fundamental asset intensity philosophy.

Underpinned by our cornerstone California assets, we focused on our oil growth strategy by accelerating our Eagle Ford Shale activity. To enhance our oil margins, we moved our Eagle Ford Shale and California pricing mechanisms away from West Texas Intermediate pricing to Brent based pricing by negotiating changes in our crude oil marketing contracts. In November, we completed $450 million in financing for a 20% preferred equity interest in our subsidiary to develop our offshore Gulf of Mexico oil assets. The financing provides capital for the development of Lucius Oil Production Facilities and for additional exploratory drilling opportunities beginning in 2012 with our large Phobos prospect. Lucius Field oil production is expected in 2014.

As a result of the weakened gas market, we strategically divested our natural gas assets in the Texas Panhandle and South Texas in 2011 for $735.8 million. We are managing our gas assets to be cash flow positive as we move into 2012 by reducing gas focused capital expenditures and expanding our hedging program. Our gas portfolio includes assets in the Haynesville Field, the Madden Field, and our equity investment in McMoRan Exploration Co. PXP owned 51 million shares of McMoRan common stock at year-end 2011.

Financially, with the current historically low interest rates, we issued \$600 million $6\frac{5}{8}\%$ Senior Notes due 2021 and \$1.0 billion $6\frac{3}{4}\%$ Senior Notes due 2022 and redeemed \$1.3 billion of higher coupon Senior Notes. These transactions resulted in lengthening our debt maturity schedule and lowering our overall interest rate. PXP continues to maintain a comprehensive hedging program to protect against downside risk and unpredictable commodity prices. Through various derivative instruments, we have significant oil and gas hedges in place through 2014. Oil and liquids sales revenue as a percentage of total revenue is expected to be approximately 90% in 2012, compared to 78% in 2011.

In late December and early January 2012, PXP repurchased 12.8 million shares of common stock, thereby reducing our share count by 9% and increasing the benefit of the forecasted increase in oil volumes and corresponding cash flow for each shareholder.

With significant proven reserves and development resource potential, we are in an excellent position to continue maximizing shareholder value. PXP's focus remains on increasing margins while targeting a significant organic oil growth rate, minimizing natural gas focused capital spending and protecting the downside risk of commodity prices for our shareholders. Our low-risk stable assets and strong margins provide a solid foundation for future growth.

The invaluable key to our operational and financial successes has been our outstanding employees and contractors who are committed to safety and environmental stewardship. Through their dedication, PXP received National Safety Council Safety Leadership awards for 20 out of 24 facilities.

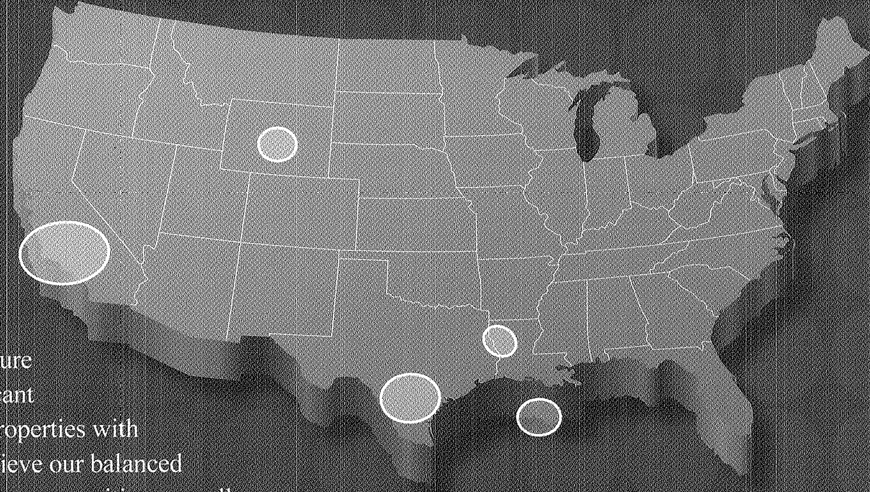
On behalf of our board of directors and employees, I thank you for your investment in PXP and appreciate your continued support as we celebrate our 10th anniversary in December 2012.

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

- Onshore California;
- Offshore California;
- the Gulf Coast Region, including Haynesville Shale and Eagle Ford Shale;
- the Gulf of Mexico; 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, Eagle Ford Shale, Haynesville Shale and Gulf of Mexico assets.

PXP

Plains Exploration & Production Company

FORM 10-K

Received SEC

APR 16 2012

Washington, DC 20549

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, 2011

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 $5.3 billion on June 30, 2011 (based on $38.12 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date). On January 31, 2012, there were 128.2 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 2012 Annual Meeting of Stockholders.

PLAINS EXPLORATION & PRODUCTION COMPANY
2011 ANNUAL REPORT ON FORM 10-K
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Part I

Part II

Part III

Part IV

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 and hydraulic fracturing;
- the effects of future laws and governmental regulation that result from the Macondo accident and oil spill in the U.S. Gulf of Mexico;
- the value of the common stock of McMoRan Exploration Co. and our ability to dispose of those shares;
- 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 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. 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, www.pxp.com. 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) 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.

ICE. IntercontinentalExchange.

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.

Probable reserves. Probable oil and gas reserves are those quantities of oil and gas that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

The proved plus probable reserves estimate must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

Where direct observation has defined a highest known oil, or HKO, elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable oil or gas based on reservoir fluid properties and pressure gradient interpretations.

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 HKO 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 proved 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", "probable reserves", "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 Gulf of Mexico; 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 risk management 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, Eagle Ford Shale, Haynesville Shale and Gulf of Mexico plays.

Oil and Gas Reserves

As of December 31, 2011, we had estimated proved reserves of 410.9 million barrels of oil equivalent of which 59% was comprised of oil and 55% was proved developed. We have a total proved reserve life of approximately 12 years and a proved developed reserve life of approximately seven years. As of December 31, 2011, and based on the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials, our proved reserves had a standardized measure of $5.1 billion. As of December 31, 2011, we had estimated probable reserves of 292.1 million barrels of oil equivalent of which 37% was comprised of oil and 2% was probable developed. 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. Unless otherwise indicated, any reference to reserves is to PXP reserves and excludes our share of McMoRan reserves.

The following table sets forth certain information with respect to our proved and probable reserves that for 2011 are based upon (1) reserve reports prepared by the independent petroleum engineers of Netherland, Sewell & Associates, Inc., or NSA, (95% of proved reserve volumes and 40% of probable reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum engineer (5% of proved reserve volumes and 60% of probable reserve volumes). In 2010, our proved reserves were based upon (1) reserve reports prepared by the independent petroleum engineers of NSA and Ryder Scott Company L.P., or Ryder Scott, (99% of proved reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum engineer (1% of proved reserve volumes). In 2009, our proved reserves were based upon reserve reports prepared by NSA and Ryder Scott. The reserve volumes and values were determined using the methods prescribed by the SEC, which require the use of an average price, calculated as the twelve-month average of the first-day-of-the-month reference price as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

We and our independent petroleum engineers used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. Our reserves have been estimated using deterministic methods. Standard engineering and geoscience methods were used, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we and our independent petroleum engineers considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on estimates of reserve volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

	As of December 31,		
	2011	**2010**	**2009**
Oil and Gas Proved Reserves			
Consolidated entities			
Oil (MBbls)			
Proved developed	151,480	150,492	144,839
Proved undeveloped	92,550	72,776	69,191
	244,030	223,268	214,030
Gas (MMcf)			
Proved developed	454,248	517,183	509,121
Proved undeveloped	547,063	639,887	363,987
	1,001,311	1,157,070	873,108
MBOE	410,915	416,113	359,548
Entity's share of equity investee (1)			
Oil (MBbls)			
Proved developed	4,921	4,315	
Proved undeveloped	542	401	
	5,463	4,716	
Gas (MMcf)			
Proved developed	39,066	46,974	
Proved undeveloped	8,982	15,394	
	48,048	62,368	
MBOE	13,471	15,111	

Table continued on following page.

	As of December 31,		
	2011	2010	2009
Oil and Gas Probable Reserves (2)			
Consolidated entities			
Oil (MBbls)			
Probable developed (3)	2,841		
Probable undeveloped	106,685		
	109,526		
Gas (MMcf)			
Probable developed (3)	14,593		
Probable undeveloped	1,080,967		
	1,095,560		
MBOE	292,119		
Standardized Measure (in thousands)			
Consolidated entities (4)	$ 5,134,181	$ 3,093,135	$ 2,224,839
Entity's shares of equity investee (1)	$ 261,911	$ 210,898	
Average Realized Price (5)			
Oil (per Bbl)	$ 104.59	$ 72.83	$ 54.38
Gas (per Mcf)	$ 4.08	$ 4.29	$ 3.53
Reference Price (6)			
Oil (per Bbl)	$ 95.99	$ 79.43	$ 61.18
Henry Hub Gas (per MMBtu)	$ 4.12	$ 4.38	$ 3.87
Reserve Life (years)	12.2	13.0	11.2

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010.
(2) 2011 is the first year we have reported probable reserves.
(3) Reflects reserves associated with incremental recovery from existing production/injection wells that require no future development costs and reserves associated with work performed on existing producers/injectors that do not meet the reasonable certainty requirements to be classified as proved.
(4) Our year-end 2011 standardized measure includes future development costs related to proved undeveloped reserves of $549 million, $557 million and $690 million in 2012, 2013 and 2014, respectively.
(5) Reflects the average realized price in our reserve reports based on the twelve-month average of the first-day-of-the-month reference prices, in each case adjusted for location and quality differentials. Historically, the market price for California crude oil differs from the established market indices in the United States due principally to the higher transportation and refining costs associated with heavy oil. Recently, however, the market price for California crude oil has strengthened relative to NYMEX and West Texas Intermediate, or WTI, primarily due to world demand and declining domestic supplies of both Alaskan and California crude oil.
(6) Reflects the twelve-month average of the first-day-of-the-month reference prices. Our reference prices are the WTI spot price for oil and the Henry Hub spot price for gas.

In 2011, we had a total of 75 MMBOE of extensions and discoveries, including 25 MMBOE in the Haynesville Shale and 22 MMBOE in the Eagle Ford Shale resulting from successful drilling during 2011 that extended and developed our proved acreage and 19 MMBOE in the deepwater Gulf of Mexico resulting from the sanctioning of the Lucius project. The divestment of our Panhandle and South Texas properties resulted in a 48 MMBOE reduction. With persistent low natural gas prices and a corresponding assumed reduction in the pace of development in the Haynesville Shale, we classified 44 MMBOE of our Haynesville Shale undeveloped reserves as probable undeveloped. These reserves meet the reasonable certainty, economic and other conditions needed to be classified as proved undeveloped reserves but the slower pace of drilling extends the development of these reserves past five years.

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.

During the three-year period ended December 31, 2011, we participated in 977 exploratory wells, of which 960 were successful, and 420 development wells, of which 416 were successful. During this period, we incurred aggregate oil and gas acquisition, exploration and development costs of $6.4 billion, approximately half of which was for acquisition and development activities. During this period, proved reserve additions from acquisitions, extensions and discoveries totaled 217 MMBOE.

All of our proved undeveloped reserves are scheduled for development within five years. As of December 31, 2011, we had proved undeveloped reserves of 184 MMBOE, a net increase of 5 MMBOE relative to December 31, 2010. Additions to proved undeveloped reserves resulted primarily from continued successful development of our Lucius oil field, Arroyo Grande and the Eagle Ford Shale. During 2011, we invested $316.2 million and converted 29 MMBOE, or 16% of our year-end 2010 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 and Eagle Ford Shale acreage in order to capture our significant leasehold on a held by production basis.

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.

Probable reserves are additional reserves that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered. In addition to the uncertainties inherent in estimating quantities and values of proved reserves, probable reserves may be assigned to areas where data control or interpretations of available data are less certain and are structurally higher than proved reserves if they are adjacent to the proved reservoirs. See Item 1A – Risk Factors – *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.*

Undeveloped reserves that meet the reasonable certainty, economic and other requirements to be classified as proved undeveloped, except that they are not expected to be developed within five years, are classified as probable reserves. In 2011, 44 MMBOE of our Haynesville Shale undeveloped reserves were classified as probable because they relate to undeveloped locations that are expected to be developed beyond five years but would otherwise meet the requirements to be classified as proved undeveloped reserves.

The reserve documentation and calculations for substantially all of our reserves are reviewed both by our internal engineers and, where noted, 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 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 department, including the Vice President of Engineering, consists of three degreed petroleum engineers, with between 22 and 35 years of industry experience, between 12 and 35 years of reservoir engineering/management experience, and between six and ten 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 NSA 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. NSA is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; it does not own an interest in our properties and is 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 Shale

During the fourth quarter of 2010, we completed the acquisition of approximately 60,000 net acres in the Eagle Ford Shale 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.

Divestments

Panhandle and South Texas Properties

In December 2011, we completed the divestment of our Texas Panhandle properties to Linn Energy, LLC. After the exercise of third party preferential rights and preliminary closing adjustments, we received approximately $554.8 million in cash. At December 31, 2011, we continue to have interests in approximately 50,000 gross leasehold acres. We expect to receive additional proceeds from future closings, as may be further modified for additional post-closing adjustments. The cash proceeds received, net of approximately $6.2 million in transaction costs, were primarily used to reduce indebtedness. Our aggregate working interest in the Texas Panhandle properties generated total sales volumes of approximately 84 MMcfe per day during the third quarter of 2011 and had 263 Bcfe of estimated proved reserves as of December 31, 2010. The transaction was effective November 1, 2011.

In December 2011, we completed the divestment of all our working interests in our South Texas conventional natural gas properties to a third party. After preliminary closing adjustments, we received $181.0 million in cash. The cash proceeds received were primarily used to reduce indebtedness. The transaction was effective September 1, 2011.

The proceeds from the 2011 sales of oil and gas properties were recorded as reductions to capitalized costs pursuant to full cost accounting rules.

Gulf of Mexico

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 limitations 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.

Development and Exploration

We expect to continue growing reserves and production through the long-term development of our existing project inventory in each of our primary operating areas and by building future development projects through exploration primarily in the Gulf of Mexico, California and liquids rich resource plays such as the Eagle Ford Shale. To implement our development and exploration plan, we will focus on:

- allocating investment capital prudently after rigorous evaluation to projects with the best economic returns;
- 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, 2011, our additions to proved reserves from extensions and discoveries totaled 210 MMBOE. During this period, we incurred aggregate oil and gas development and exploration costs of $4.5 billion.

Our 2012 capital budget is approximately $1.6 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 the Eagle Ford Shale, California, Gulf of Mexico and the Haynesville Shale. We continue to aggressively manage our inventory, our cost structure and our financial flexibility.

Description of Properties

Our oil and gas operations are concentrated onshore California, offshore California, the Gulf Coast Region, the Gulf of Mexico 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, the Eagle Ford Shale, the Gulf of Mexico and the Haynesville Shale. Also, we have continued exploration primarily in the Gulf of Mexico, California and liquids rich resource plays such as the Eagle Ford Shale. Capital additions to our oil and gas properties were $1.9 billion in 2011.

The following table sets forth information with respect to our proved and probable oil and gas reserves as of December 31, 2011:

	As of December 31, 2011					
	Proved Reserves			Probable Reserves		
	Proved Developed	Proved Undeveloped	Total Proved	Probable Developed (1)	Probable Undeveloped	Total Probable
			(MMBOE)			
Consolidated entities						
Onshore California	135.0	68.9	203.9	2.9	90.2	93.1
Offshore California	13.5	-	13.5	-	3.4	3.4
Gulf Coast Region and Gulf of Mexico	51.8	114.3	166.1	-	193.2	193.2
Rocky Mountains and Other	26.9	0.5	27.4	2.4	-	2.4
Total	227.2	183.7	410.9	5.3	286.8	292.1
Entity's share of equity investee (2)	11.4	2.1	13.5			

(1) Reflects reserves associated with incremental recovery from existing production/injection wells that require no future development costs and reserves associated with work performed on existing producers/injectors that do not meet the reasonable certainty requirements to be classified as proved.

(2) Amounts relate to our equity investment in McMoRan.

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 2011, we spent $105 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. Drilling was concentrated in the Inglewood field where we drilled 39 wells, including two injector wells. Our net average daily LA Basin sales volumes were 11.2 MBOE per day in the fourth quarter of 2011. In 2012, 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 $116 million in 2011 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. During 2011, we drilled 146 wells, including 27 injector wells, in the San Joaquin Basin. Our net average daily San Joaquin Basin sales volumes were 19.3 MBOE per day in the fourth quarter of 2011.

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 2012, 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 2011, we spent $63 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 2011.

Construction of a produced water reclamation facility is underway. Upon completion of the facility in mid-2013, we will begin to dewater the reservoir, allowing for improved efficiency of steam flood and continued development drilling. Additionally, we have signed a ten-year operations agreement for the facility which will commence upon commercial operations.

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 2011 were 2.8 MBOE per day.

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 access the Federal OCS Monterey Reservoir by extended reach directional wells and support facilities which lie within the onshore Lompoc Field. Our combined net average daily sales volumes from our Pt. Pedernales and Lompoc Fields averaged 5.7 MBOE per day in the fourth quarter of 2011. In 2011, we spent $25 million on capital projects primarily associated with equipment improvements, including a significant platform upgrade associated with capacity expansion to accommodate the drilling of additional wells. During 2012, we plan to drill additional extended reach Monterey wells in this area and continue our focus on plug back recompletions to maintain production.

Gulf Coast Region

Eagle Ford Shale

At December 31, 2011, we own interests in oil and gas properties on approximately 89,000 gross acres (60,000 net acres) with 255 square miles of 3-D seismic data located in the Eagle Ford Shale. The Eagle Ford Shale is Upper Cretaceous in age, and typical well depths range from 9,500 feet to 11,500 feet. The area is currently being developed with horizontal wells with lateral lengths ranging from 3,500 feet to 6,000 feet at a measured total depth from 14,500 to 17,500 feet. Based on the 80 to 130 acre well spacing, we anticipate over 500 potential well locations.

Our net average daily sales volumes during the fourth quarter of 2011 were 9.1 MBOE per day, an increase of greater than 300% from the 2.2 MBOE per day net average during the first quarter of 2011.

We spent $502 million of capital in 2011 focused on continued development drilling and the completion of seven production facilities. At December 31, 2011, we had seven rigs drilling horizontal development wells on our acreage. For 2012, we allocated approximately $655 million of our capital budget to Eagle Ford Shale activity and plan to focus on development drilling and the completion of 12 additional production facilities, including two existing facilities modified to bring on additional wells. During 2012, we plan to have nine to 11 rigs drilling horizontal development wells on our acreage.

Haynesville Shale

As of December 31, 2011, we have rights to approximately 432,000 gross acres (84,000 net acres) in the Haynesville Shale that we acquired from Chesapeake Energy Corporation, including approximately 54,000 net acres of leasehold that we believe is also prospective for the Bossier Shale. 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. Based on the potential of 80 acre well spacing, we anticipate that there could be over 11,000 unrisked potential drilling locations. During 2011, 2010 and 2009, we spent $14 million, $16 million and $59 million, respectively, to acquire approximately 1,100, 1,200 and 5,000 net additional acres, respectively, in the Haynesville Shale. During 2011, we divested 3,000 net acres and released 20,200 net acres that were deemed to be outside of our primary focus area.

Our net average daily sales volumes during the fourth quarter of 2011 were 199.8 MMcfe per day, a 23% increase from the 161.9 MMcfe per day net average during the first quarter of 2011. The rate of increase in sales volumes is expected to slow as the rig count continues to decline.

We spent $363 million of capital in 2011 focused on converting undeveloped leases to leases held by production. For 2012, we allocated approximately $140 million of our capital budget to Haynesville Shale activity and plan to continue to focus on the development of our undeveloped leasehold and improved recovery efficiency through infill drilling.

Deepwater Gulf of Mexico

Our deepwater Gulf of Mexico portfolio is anchored by Lucius, a high-quality oil discovery, and a comprehensive exploration portfolio with interests in 102 blocks containing 29 prospects or leads in Pliocene, Miocene and lower Tertiary reservoirs.

In October 2011, we entered into a securities purchase agreement with EIG Global Energy Partners, or EIG, pursuant to which we received $430.2 million of net cash proceeds in November 2011, upon closing of the transaction, in exchange for a 20% equity interest in Plains Offshore Operations Inc., or Plains Offshore, a former wholly owned subsidiary. Plains Offshore holds all of our oil and natural gas properties and assets located in the United States Gulf of Mexico in water depths of 500 feet or more. The proceeds raised are expected to be used to fund Plains Offshore's share of capital investment in the Lucius oil field and the Phobos prospect exploratory drilling planned for 2012 and other activities. Under the agreement, Plains Offshore issued to EIG managed funds and accounts, or the EIG Funds, (i) 450,000 shares of Plains Offshore 8% convertible perpetual preferred stock and (ii) non-detachable warrants to purchase in aggregate 9,121,000 shares of Plains Offshore's common stock with an exercise price of $20 per share. In addition, Plains Offshore issued 87 million shares of Plains Offshore Class A common stock, which will be held in escrow until the conversion and cancellation of the preferred stock or the exercise of the warrants held by EIG. In November 2011, Plains Offshore also entered into a senior credit facility providing for $300 million of commitments to fund future capital costs beyond that already raised.

Through our ownership in Lucius, located in the deepwater U.S. Gulf of Mexico, we joined the Lucius and Hadrian working interest partners and executed a unit participation and unit operating agreement effective June 1, 2011. As part of the agreements, we have agreed to share in our portion of certain long lead equipment orders and detailed engineering work.

Plains Offshore and its partners have entered into various agreements with third parties for long-term oil and gas gathering and transportation services at the Lucius oil field. Beginning in 2014, Plains Offshore will pay guaranteed fixed minimum monthly fees plus additional variable gathering fees based upon actual throughput. The commitments of Plains Offshore under the oil gathering agreements are guaranteed by PXP.

In December 2011, the operator and our working interest partners sanctioned development of Lucius. Lucius will be developed with a truss spar floating production facility with the capacity to produce in excess of 80 MBbl per day and 450 MMcfe per day. The development drilling program is expected to begin in 2012 with achievement of first production anticipated in 2014.

During the third quarter of 2011, we determined not to develop the Friesian prospect and the lease terminated by its terms. The accumulated costs of approximately $460 million associated with the project were transferred to the full cost pool.

Rocky Mountains

Wind River Basin

We own an approximate 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. Our net average daily sales volumes during the fourth quarter of 2011 were 27.2 MMcfe from the Wind River Basin.

During 2011, we spent $5 million on capital projects in the Madden Deep Unit. After completion of repair work following a fire in 2010 that affected a portion of the Lost Cabin Gas Plant, production was back to full capacity during the first quarter of 2011. In 2012, we are focused on maintaining production and high-grading the remaining development drilling inventory.

Big Horn Basin

We hold leases covering 126,000 gross acres (111,000 net acres) in the Big Horn Basin located in Wyoming. We drilled two wells in 2011 that tested high-quality oil in small quantities. During 2012, we plan to monitor industry activity in this play.

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,		
	2011	2010	2009
Consolidated entities			
Property acquisition costs			
Unproved properties	$ 36,562	$ 612,471	$ 1,121,644
Proved properties	9,236	48,078	5,072
Exploration costs	1,147,858	719,004	1,309,396
Development costs	708,519	363,242	272,820
	$ 1,902,175	$ 1,742,795	$ 2,708,932
Entity's share of equity investee (1)			
Property acquisition costs			
Unproved properties	$ 15,523		
Proved properties	-		
Exploration costs	175,802		
Development costs	17,190		
	$ 208,515		

(1) Amounts relate to our equity investment in McMoRan acquired 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, 2011, 2010 and 2009.

	Inglewood (1)	Haynesville Shale (1)	Other	Total
2011				
Oil and liquids sales (MBbls)	2,332	-	15,540	17,872
Gas (MMcf)				
Production	969	68,015	42,593	111,577
Used as fuel	35	-	2,073	2,108
Sales	934	68,015	40,520	109,469
MBOE				
Production	2,494	11,336	22,638	36,468
Sales	2,488	11,336	22,293	36,117
Average realized sales price before derivative transactions (2)				
Oil (per Bbl)	$ 96.65	$ -	$ 83.87	$ 85.53
Gas (per Mcf)	4.10	3.85	4.01	3.91
Per BOE	92.14	23.11	65.75	54.18
Average production cost per BOE (3)				
Lease operating expenses	$ 21.23	$ 1.71	$ 11.78	$ 9.27
Steam gas costs	-	-	2.94	1.81
Electricity	5.67	-	1.22	1.14
Gathering and transportation	0.17	4.38	0.54	1.72

Table continued on following page.

	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
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

(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, collar and swap contracts entered into with financial institutions.

A substantial portion of our oil reserves are located in California and approximately 56% of our production is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). Historically, the market price for California crude oil differs from the established market indices in the United States due principally to the higher transportation and refining costs associated with heavy oil. Recently, however, the market price for California crude oil has strengthened relative to NYMEX and WTI primarily due to world demand and declining domestic supplies of both Alaskan and California crude oil.

Our heavy crude is primarily sold to ConocoPhillips. In August 2011, we replaced our previous contract with a new marketing contract with ConocoPhillips effective January 1, 2012 that covers approximately 90% of our California production, extends the dedication from January 1, 2015 to January 1, 2023 and replaces the percent of NYMEX index pricing mechanism with a market-based pricing approach. During 2011, we received approximately 89% of the NYMEX index price for crude oil sold under the ConocoPhillips contract, which represented approximately 50% of our total crude oil production. Separately, we executed an agreement with a third party purchaser to sell a large portion of our Eagle Ford Shale crude oil using a Light Louisiana Sweet based pricing mechanism. Due to these new marketing contracts, we expect oil price realizations on a significant portion of our crude oil production to increase relative to WTI beginning in 2012.

Approximately 20% of our 2011 crude oil production was sold under contracts that provide for NYMEX less a fixed price differential (as of December 31, 2011 the fixed price differential averaged $4.66 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 50% of our gas production is sold monthly based on industry recognized, published index pricing. The remainder is priced daily on the spot market. Fluctuations between spot and index prices can significantly impact the overall differential to the Henry Hub.

During 2011, 2010 and 2009, sales to ConocoPhillips accounted for 41%, 57% and 44%, respectively, of our total revenues. During 2011, sales to Tesoro Corporation and Valero Energy Corporation accounted for 13% and 11%, respectively, of our total revenues. The contract with Tesoro Corporation expired in November 2011. We did not renew this contract, and upon expiration we entered into a contract with ConocoPhillips for these volumes. During 2009, sales to Plains Marketing, L.P., or PMLP, accounted for 22% 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 2011, 2010 and 2009, 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 do not currently require letters of credit or other collateral from the above stated purchasers to support trade receivables. Accordingly, a material adverse change in a purchaser'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.

Acreage

The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2011:

	Developed Acres		Undeveloped Acres (1)	
	Gross	Net	Gross	Net
California				
Onshore	61,311	60,734	50,208	34,234
Offshore	43,335	39,062	-	-
Louisiana				
Onshore	282,560	55,060	103,325	20,134
Offshore	5,670	1,323	567,947	189,286
Nevada	-	-	217,431	217,431
Texas	116,481	72,230	103,959	50,511
Utah	-	-	65,871	34,346
Wyoming	72,340	14,342	200,132	174,105
Other states (2)	2,884	316	9,387	7,050
	584,581	243,067	1,318,260	727,097

(1) Approximately 21% of our total net undeveloped acres is covered by leases that expire from 2012 to 2014.
(2) Other states include Arkansas, Illinois, Kansas, Mississippi and Montana.

Productive Wells

As of December 31, 2011, we had working interests in 3,190 gross (2,879 net) active producing oil wells and 1,423 gross (209 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, 2011, we owned an interest in two gross wells containing multiple completions.

Drilling Activities

The number of oil and gas wells completed during the years ended December 31, 2011, 2010 and 2009 is set forth below:

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells (1)						
Oil	36.0	27.6	6.0	3.1	1.0	1.0
Gas	443.0	42.7	318.0	38.3	156.0	19.6
Dry	3.0	-	4.0	2.2	10.0	6.6
	482.0	70.3	328.0	43.6	167.0	27.2
Development Wells						
Oil	192.0	165.2	109.0	106.4	16.0	12.7
Gas	67.0	22.5	8.0	2.7	24.0	12.4
Dry	2.0	1.9	1.0	1.0	1.0	0.2
	261.0	189.6	118.0	110.1	41.0	25.3
	743.0	259.9	446.0	153.7	208.0	52.5

(1) Includes extension wells.

At December 31, 2011, there were 148 gross exploratory and 37 gross development wells (34.1 net exploratory and 6.5 net development wells) in progress including 147 wells in the Haynesville Shale area where we had approximately 29 rigs actively drilling horizontal wells at year-end. We had 35 wells in progress in the Eagle Ford Shale where we had seven rigs actively drilling horizontal wells at year-end.

Investment

At December 31, 2011 and 2010, we owned 51.0 million shares of McMoRan common stock, approximately 31.6% and 32.4%, respectively, of its 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 filed 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 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). The one year restriction ended on December 30, 2011, and we may now sell shares of McMoRan common stock pursuant to underwritten offerings, in periodic sales under the shelf registration statement 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 2011, we primarily focused our efforts on the Montebello property. Our objective relative to the Montebello property 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 property and are engaged in pre-entitlement activities in Arroyo Grande and Lompoc. 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 2011, we spent approximately $4 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.

BOEM/BSEE. The United States Bureau of Ocean Energy Management, or BOEM, and the Bureau of Safety and Environmental Enforcement, or BSEE, (together the BOEM/BSEE) were established on October 1, 2011 as agencies of the Department of Interior that were previously one agency known as the Bureau of Ocean Energy Management, Regulation and Enforcement, or BOEMRE. These two newly formed bureaus have broad authority to regulate our oil and gas operations on offshore leases in federal waters. They must approve and grant permits in connection with our exploration, drilling, development and production plans in federal waters. Additionally, BOEM/ BSEE will implement regulations and "Notices to Lessees" already issued by BOEMRE requiring offshore production facilities to meet stringent engineering, construction, safety and environmental specifications, including regulations restricting the flaring or venting of gas, governing the plugging and abandonment of wells, regulating workplace safety, and controlling the removal of production facilities. Under certain circumstances, the BOEM/BSEE 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 BOEM/BSEE have 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 BOEM/ BSEE because of staffing, economic, environmental or other reasons (or other actions taken by the BOEM/BSEE under its regulatory authority) could adversely affect our operations.

Surety and Oil Spill Financial Responsibility Requirements. Historically, we have complied with the BOEM/BSEE regulations and held any bonds, or provided the financial assurances, required for our leases in federal waters. However, upon our contribution of the properties to Plains Offshore, as a lessee in the deepwater U.S. Gulf of Mexico, Plains Offshore must also comply with the regulations. To cover the various obligations of lessees in federal waters, the BOEM/BSEE generally requires that lessees have substantial U.S. assets and net worth or post bonds or other acceptable assurances that such obligations will be met. We are subject to the following types of surety requirements with BOEM: (i) supplemental bonding, which is required to be provided by all lessees and specifically covers the plugging and abandonment obligations associated with a lease, and (ii) oil spill financial responsibility, generally provided by operators pursuant to the Oil Pollution Act of 1990 as amended, or OPA. The OPA imposes a variety of requirements related to the prevention of and response to oil spills into waters of the United States, including the Outer Continental Shelf, which includes the U.S. Gulf of Mexico. The OPA subjects operators of offshore leases and owners and operators of oil handling facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. The OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. The OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating oil production facilities on the Outer Continental Shelf, although the Secretary of Interior may increase this amount up to $150 million in certain situations. The cost of these bonds or other surety could be substantial and there is no assurance that bonds or other surety could be obtained in all cases.

Pipeline Safety 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, or DOT, 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. We believe that our pipeline operations are in substantial compliance with applicable requirements.

Recently enacted pipeline safety legislation, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The Pipeline Hazardous Materials Safety Administration of the DOT has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service due to more stringent and comprehensive safety regulation and higher penalties for violations of those regulations.

Sale and Transportation of Gas and Oil. The Federal Energy Regulatory Commission, or the FERC, approves the construction of interstate gas pipelines and the rates and service conditions for the interstate transportation of gas, oil and other liquids by pipeline. Some of our pipelines related to the Point Arguello unit are subject to this regulation by the FERC. Although the FERC does not regulate the production of gas, the FERC exercises regulatory authority over wholesale sales of gas in interstate commerce through the issuance of blanket marketing certificates that authorize the wholesale sale of gas at market rates and the imposition of a code of conduct on blanket marketing certificate holders that regulate certain affiliate interactions. The FERC does not regulate the sale of oil or petroleum products or the construction of oil or other liquids pipelines. The FERC also has oversight of the performance of wholesale natural gas markets, including the authority to facilitate price transparency and to prevent market manipulation. In furtherance of this authority, the 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 minimum level. The agency's actions are intended to foster increased competition within all phases of the gas industry. To date, the 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.

The 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 or oil industries. 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.

Market Manipulation Regulations. The FERC with respect to natural gas, the Federal Trade Commission with respect to petroleum and petroleum products, and the Commodity Futures Trading Commission with respect to commodity and futures markets, operating under various statutes have each adopted anti-market manipulation regulations, which prohibit, among other things, fraud and price manipulation in the respective markets. Should we violate anti-manipulation laws and regulations we could be subject to substantial one or more of the following: civil penalties, potential disgorgement of profits, the payment of refunds and criminal penalties. We could also be subject to third-party damage claims.

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, or SDWA, 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. The EPA adopted the so-called "Tailoring Rule" in May 2010, which imposes permitting and best available control technology requirements on the largest greenhouse gas stationary sources. In November 2010, the EPA also published mandatory reporting rules for certain oil and gas facilities, with reports due later in 2012. Some of our facilities are subject to these requirements. In addition, many 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. In October 2011, the California Air Resources Board, or CARB, adopted the final cap and trade regulation, including a delay in the start of the cap and trade rule's compliance obligations until 2013. Because our operations emit greenhouse gases, our operations in California are subject to regulations issued under the California Global Warming Solutions Act of 2006, or Assembly Bill 32. These regulations increase our costs for those operations and adversely affect our operating results.

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.

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.

Hydraulic Fracturing. Our operations utilize the practice of hydraulic fracturing for new oil and natural gas wells. The practice of hydraulic fracturing continues to receive significant regulatory and legislative attention at the federal, state, and local level. Several federal agencies including the EPA and the U.S. Bureau of Land Management are reviewing current regulations related to the practice of hydraulic fracturing and are considering adopting additional regulations in the future. From time to time, legislation has been introduced in Congress to amend the federal SDWA to eliminate exemptions for most fracturing activities. Similar efforts to review the practice and impose new regulatory conditions are taking place at the state and local level in states where we operate, several of which have adopted or are considering new regulations and statutes. These new requirements will (and future regulatory and legislative changes, if enacted, could) create new permitting and financial assurance requirements, require us to adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. Although we would not be impacted to a greater degree than other similarly situated oil and gas companies, the imposition of stringent new regulatory and permitting requirements related to the practice of hydraulic fracturing could significantly increase our cost of doing business and create adverse effect 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, and maintaining bonding and insurance requirements to drill, operate, plug and abandon. We are also subject to laws and regulations that require us to restore the surface associated with our wells, regulate 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. In certain instances we may also be subject to permit conditions that require us to reabandon an old well as a condition of adding a new injection well. 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, 2012, we had 880 full-time employees, 331 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 and probable 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. 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, with the variability likely to be higher for probable reserves estimates.

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. 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. As of February 2012, the twelve-month average of the first-day-of-the-month reference price for natural gas has declined from $4.12 per MMBtu at year-end 2011 to $3.86 per MMBtu, while the comparable price for oil has increased from $95.99 per Bbl at year-end 2011 to $97.28 per Bbl. 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 31.6% of the outstanding shares of common stock of McMoRan as of December 31, 2011. 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, result in losses and have a significant impact on our working capital. 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, may result in us making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas and 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 and ICE 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 the U.S. Gulf of Mexico. 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 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 some permits have been issued, but at a much slower rate than before the Macondo accident.

We have offshore exploration, development and production ongoing in the Gulf of Mexico and California. The BOEM/BSEE 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.

A significant portion 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 a significant portion of our 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 which could negatively impact our business, financial condition and results of operations, as well as our ability to access capital.

During 2011, there was significant volatility within the global economy, particularly in certain countries of the European Union. Should this financial concern continue to cause disruption, it may negatively impact stock price and credit capacity for certain issuers, even those without exposure to the affected countries.

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 global economy and financial markets may impact the credit ratings of our current and potential counterparties, including those counterparties who may have exposure to certain European sovereign debt, 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 facilities 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 facilities. The commitments under our senior revolving credit facility and the Plains Offshore senior credit facility are from a diverse syndicate of 21 lenders. At December 31, 2011, no single lender's commitments under both credit facilities combined represented more than 8% 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 2011, the twelve-month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) were $95.99 per Bbl for oil and $4.12 per MMBtu for natural gas. At December 31, 2011, the ceiling with respect to our domestic oil and gas properties exceeded the net capitalized costs of those properties by approximately 30%.

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 BOEM/BSEE 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.

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. From time to time the U.S. Congress has considered climate-related legislation to reduce emissions of greenhouse gases. In addition, many 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. In California, for example Assembly Bill 32 requires the CARB 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. In October 2011, the CARB adopted the final cap and trade regulation, including a delay in the start of the cap and trade rule's compliance obligations until 2013.

Because our operations emit greenhouse gases, our operations in California are subject to regulations issued under Assembly Bill 32. These regulations increase our costs for those operations and adversely affect our operating results. The EPA has also adopted regulations imposing permitting and best available control technology requirements on the largest greenhouse gas stationary sources, 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. The Montebello field operates under a number of federal and California permits that are over and above what may be required in our other California facilities. The primary reason for the additional permits and associated restrictions on property use is the property's location within what has been designated critical habitat for the federally threatened songbird, known as the California gnatcatcher, in accordance with Section 7 of the federal Endangered Species Act of 1973. 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.

Legislation and regulatory initiatives relating to hydraulic fracturing could increase our cost of doing business and adversely affect our operations.

From time to time, legislation has been introduced in Congress to amend the federal SDWA to eliminate exemptions for most fracturing activities. Similar efforts to review the practice and impose new regulatory conditions are taking place at the state and local level in states where we operate, several of which have adopted or are considering new regulations and statutes. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formation to stimulate oil and natural gas production. The use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale formations such as the Haynesville Shale and the Eagle Ford Shale. These new requirements will (and future regulatory and legislative changes, if enacted, could) create new permitting and financial assurance requirements, require us to adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. The imposition of stringent new regulatory and permitting requirements related to the practice of hydraulic fracturing could significantly increase our cost of doing business and adversely affect our operations.

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, 2011, we had leases on approximately 84,000 net acres in the Haynesville Shale area and approximately 60,000 net acres in the Eagle Ford Shale area. Over 85% of our acreage in the Haynesville Shale and over 25% of our acreage in the Eagle Ford Shale is currently held by production or held by operations. 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 Eagle Ford Shale may cause pipeline and gathering system capacity constraints that could limit our ability to sell our oil and gas.

Because of the current economic climate, certain pipeline projects that are planned for the Haynesville Shale and the Eagle Ford Shale 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, 2011, goodwill totaled $535 million and represented approximately 5% 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 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 2013 budget proposal, released by the Office of Management and Budget on February 13, 2012, is the elimination or deferral of certain 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 have been included in legislation that has recently been considered by 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 containing 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 our properties, including our Haynesville Shale acreage and portions of our Eagle Ford Shale acreage, 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, result in lower production and materially and adversely affect our financial condition and results of operations.

The high cost or unavailability of drilling rigs, equipment, supplies and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have an adverse effect on our business, financial condition or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment or supplies. During these periods, the costs of rigs, equipment and supplies are substantially greater and their availability may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have an adverse effect on our business, financial condition or 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. *Mine Safety Disclosures*

Not applicable.

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
2011		
1st Quarter	$ 40.06	$ 31.90
2nd Quarter	38.72	32.61
3rd Quarter	41.96	22.27
4th Quarter	37.21	20.25
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

At January 31, 2012, we had approximately 2,338 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 senior revolving credit facility and indentures restrict our ability to pay cash dividends.

Issuer Purchases of Equity Securities

On December 17, 2007, we announced that our Board of Directors had authorized the repurchase of up to $1.0 billion of PXP common stock from time to time in open market transactions or privately negotiated transactions at our discretion, subject to market conditions and other factors. The following is a summary of our repurchases of common stock during the three-month period ended December 31, 2011 under this plan:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
		(in thousands, except per share data)		
December 1 to December 31, 2011	10,415	$ 34.73	10,415	$ 334,079

In addition, we repurchased an additional 2,390 shares in January 2012. Subsequent to these repurchases, our Board of Directors reset the authorization to $1.0 billion of PXP common stock and extended the program until January 2016.

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, 2011 and 2010 and the related consolidated statements of income and cash flows for each of the three years in the period ended December 31, 2011 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,				
	2011 (1)	2010 (2)	2009	2008 (3)	2007 (4)
Income Statement Data					
Revenues	$ 1,964,488	$ 1,544,595	$ 1,187,130	$ 2,403,471	$ 1,272,840
Costs and Expenses					
Production costs	558,975	451,902	423,967	626,428	413,122
General and administrative	134,044	136,437	144,586	153,306	124,006
Depreciation, depletion, amortization and accretion	681,655	551,118	421,580	621,484	316,078
Impairment of oil and gas properties (5)	-	59,475	-	3,629,666	-
Legal recovery	-	(8,423)	(87,272)	-	-
Other operating (income) expense	(735)	(4,130)	2,136	-	-
	1,373,939	1,186,379	904,997	5,030,884	853,206
Income (Loss) from Operations	590,549	358,216	282,133	(2,627,413)	419,634
Other Income (Expense)					
Gain on sale of assets (6)	-	-	-	65,689	-
Interest expense	(161,316)	(106,713)	(73,811)	(116,991)	(68,908)
Debt extinguishment costs (7)	(120,954)	(1,189)	(12,093)	(18,256)	-
Gain (loss) on mark-to-market derivative contracts (8)	81,981	(60,695)	(7,017)	1,555,917	(88,549)
Loss on investment measured at fair value (9)	(52,675)	(1,551)	-	-	-
Other income (expense)	3,356	15,942	27,968	(12,575)	6,322
Income (Loss) Before Income Taxes	340,941	204,010	217,180	(1,153,629)	268,499
Income tax benefit (expense)					
Current	25,952	93,090	(45,091)	(230,815)	4,677
Deferred	(160,214)	(193,835)	(35,784)	675,350	(114,425)
Net Income (Loss)	206,679	$ 103,265	$ 136,305	$ (709,094)	$ 158,751
Net income attributable to noncontrolling interest in the form of preferred stock of subsidiary	(1,400)				
Net Income Attributable to Common Stockholders	$ 205,279				
Earnings (Loss) per Common Share					
Basic	$ 1.45	$ 0.74	$ 1.10	$ (6.52)	$ 2.02
Diluted	$ 1.44	$ 0.73	$ 1.09	$ (6.52)	$ 1.99
Weighted Average Common Shares Outstanding					
Basic	141,227	140,438	124,405	108,828	78,627
Diluted	142,999	141,897	125,288	108,828	79,808

Table continued on following page.

	Year Ended December 31,				
	2011 (1)	2010 (2)	2009	2008 (3)	2007 (4)
Cash Flow Data					
Net cash provided by operating activities	$ 1,110,755	$ 912,470	$ 499,046	$ 1,371,409	$ 588,112
Net cash used in investing activities	(1,154,591)	(1,575,308)	(1,280,399)	(227,790)	(2,243,137)
Net cash provided by (used in) financing activities	456,500	667,413	471,337	(857,190)	1,679,572

	As of December 31,				
	2011 (1)	2010 (2)	2009	2008 (3)	2007 (4)
Balance Sheet Data					
Assets					
Cash and cash equivalents	$ 419,098	$ 6,434	$ 1,859	$ 311,875	$ 25,446
Other current assets	1,022,279	396,453	304,776	1,164,566	649,474
Property and equipment, net	7,725,295	7,220,752	6,832,722	4,513,396	8,377,227
Goodwill	535,140	535,144	535,237	535,265	536,822
Investment (9)	-	664,346	-	-	-
Other assets	89,660	71,808	60,137	586,813	104,382
	$ 9,791,472	$ 8,894,937	$ 7,734,731	$ 7,111,915	$ 9,693,351
Liabilities and Equity					
Current liabilities	$ 626,186	$ 533,689	$ 682,551	$ 993,645	$ 818,046
Long-term debt	3,760,952	3,344,717	2,649,689	2,805,000	3,305,000
Other long-term liabilities	247,205	278,516	269,762	191,534	272,627
Deferred income taxes	1,461,897	1,355,050	933,748	744,456	1,959,431
Stockholders' equity	3,264,636	3,382,965	3,198,981	2,377,280	3,338,247
Noncontrolling interest Preferred stock of subsidiary	430,596	-	-	-	-
	$ 9,791,472	$ 8,894,937	$ 7,734,731	$ 7,111,915	$ 9,693,351

(1) Reflects the December 2011 divestiture of interests in our Texas Panhandle and South Texas conventional natural gas properties.

(2) 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 Shale oil and gas condensate windows during the fourth quarter of 2010.

(3) 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.

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

(5) 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.

(6) Represents the gain on the sale of our investment in Collbran Valley Gas Gathering, LLC.

(7) In December 2011, we recognized $121.0 million of debt extinguishment costs, including $30.9 million in unamortized debt issue costs and original issue discount, in connection with our debt retirement transactions.

(8) 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.

(9) Our investment is measured at fair value with gains and losses recognized on the income statement. Our investment was classified as a current asset at December 31, 2011.

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 Gulf of Mexico; 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 risk management 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, Eagle Ford Shale, Haynesville Shale and Gulf of Mexico plays. As of December 31, 2011, we had estimated proved reserves of 410.9 MMBOE, of which 59% was comprised of oil and 55% 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 assets include 51.0 million shares of McMoRan common stock, approximately 31.6% of its common shares outstanding. We measure our equity investment at fair value. Unrealized gains and losses on the investment are reported in our income statement and could result in volatility in our earnings. See Item 7A – Quantitative and Qualitative Disclosures About Market Risk – Equity Price Risk.

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

Divestments

In December 2011, we completed the divestment of our Texas Panhandle properties to Linn Energy, LLC. After the exercise of third party preferential rights and preliminary closing adjustments, we received approximately $554.8 million in cash. At December 31, 2011, we continue to have interests in approximately 50,000 gross leasehold acres. We expect to receive additional proceeds from future closings, as may be further modified for additional post-closing adjustments. The cash proceeds received, net of approximately $6.2 million in transaction costs, were primarily used to reduce indebtedness. Our aggregate working interest in the Texas Panhandle properties generated total sales volumes of approximately 84 MMcfe per day during the third quarter of 2011 and had 263 Bcfe of estimated proved reserves as of December 31, 2010. The transaction was effective November 1, 2011.

In December 2011, we completed the divestment of all our working interests in our South Texas conventional natural gas properties to a third party. After preliminary closing adjustments, we received $181.0 million in cash. The cash proceeds received were primarily used to reduce indebtedness. The transaction was effective September 1, 2011.

The proceeds from the 2011 sales of oil and gas properties were recorded as reductions to capitalized costs pursuant to full cost accounting rules.

Gulf of Mexico

In October 2011, we entered into a securities purchase agreement with EIG, pursuant to which we received $430.2 million of net cash proceeds in November 2011, upon closing of the transaction, in exchange for a 20% equity interest in Plains Offshore. Plains Offshore holds all of our oil and natural gas properties and assets located in the United States Gulf of Mexico in water depths of 500 feet or more. The proceeds raised are expected to be used to fund Plains Offshore's share of capital investment in the Lucius oil field and the Phobos prospect exploratory drilling planned for 2012 and other activities. Under the agreement and upon closing of the transaction, Plains Offshore issued to the EIG Funds (i) 450,000 shares of Plains Offshore 8% convertible perpetual preferred stock and (ii) non-detachable warrants to purchase in aggregate 9,121,000 shares of Plains Offshore's common stock with an exercise price of $20 per share. In addition, Plains Offshore issued 87 million shares of Plains Offshore Class A common stock, which will be held in escrow until the conversion and cancellation of the preferred stock or the exercise of the warrants held by EIG. The preferred stock will pay quarterly cash dividends of 6% per annum and an additional 2% per annum dividend. The 2% dividend may be deferred and accumulated quarterly until paid. The shares of preferred stock also fully participate, on an as-converted basis at four times, in cash dividends distributed to any class of common stockholders of Plains Offshore. In November 2011, Plains Offshore also entered into a senior credit facility providing for $300 million of commitments to fund future capital costs beyond that already raised. PXP guarantees the Plains Offshore senior credit facility.

Debt Offering and Tender Offers

In November 2011, we issued $1 billion of 6¾% Senior Notes due 2022, or the 6¾% Senior Notes, at par. We received approximately $984 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.

In December 2011, we made payments totaling approximately $1.4 billion, including premiums, to retire $520.7 million of the $600 million outstanding principal amount of our 7¾% Senior Notes due 2015, or the 7¾% Senior Notes, $380.1 million of the $565 million outstanding principal amount of our 10% Senior Notes due 2016, or the 10% Senior Notes, and $423.1 million of the $500 million outstanding principal amount of our 7% Senior Notes due 2017, or the 7% Senior Notes. In connection with the retirement of the 7¾% Senior Notes, 10% Senior Notes and 7% Senior Notes, we recorded $121.0 million of debt extinguishment costs.

Derivatives

In December 2011, we entered into natural gas swap contracts, at an average price of $4.27 per MMBtu, on 110,000 MMBtu per day for 2013.

During the period from January 1, 2012 through February 22, 2012, we converted 5,000 of the 22,000 BOPD of Brent crude oil put option contracts in 2013 to three-way collars. These modified three-way collars have a floor price of $90 per barrel with a limit of $70 per barrel and a weighted average ceiling price of $126.08 and eliminates approximately $11 million of deferred premiums. Additionally, we entered into the following Brent oil derivatives for 2013 and 2014:

- Brent crude oil put option spread contracts on 13,000 BPOD for 2013 with a floor price of $100 per barrel and a limit of $80 per barrel.

- Brent three-way collars on 25,000 BOPD for 2013 that have a floor price of $100 per barrel with a limit of $80 per barrel and a weighted average ceiling price of $124.29 per barrel.

- Brent crude oil put option spread contracts on 20,000 BOPD for 2014 with a floor price of $90 per barrel and a limit of $70 per barrel.

In February 2012, we entered into natural gas swap contracts, at an average price of $4.16 per MMBtu, on 70,000 MMBtu per day for 2014.

Stock Repurchase Program

During the year ended December 31, 2011, we repurchased 10.4 million common shares at an average cost of $34.73 per share totaling $361.7 million.

In January 2012, we completed the purchase of an additional 2.4 million common shares at an average cost of $37.02 per share totaling $88.5 million. Subsequent to those purchases, our Board of Directors reset the authorization to $1.0 billion of PXP common stock, all of which is available for repurchase, and extended the program until January 2016.

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. 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, 2011, the ceiling with respect to our domestic oil and gas properties exceeded the net capitalized costs of those properties by approximately 30%.

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 expense, or G&A, consists primarily of salaries and related benefits of administrative personnel (including stock-based compensation), office rent, systems costs and other administrative costs.

Results Overview

For the year ended December 31, 2011, we reported net income attributable to common stockholders of $205.3 million, on total revenues of $2.0 billion. This compares to net income of $103.3 million, on total revenues of $1.5 billion for the year ended December 31, 2010, and net income of $136.3 million, on total revenues of $1.2 billion for the year ended December 31, 2009.

Significant transactions that affect comparisons between the periods include the divestment of our Panhandle and South Texas properties in the fourth quarter of 2011, the divestment of our U.S. Gulf of Mexico shallow water shelf properties to McMoRan and the acquisition of our Eagle Ford Shale properties during the fourth quarter of 2010.

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,		
	2011	2010	2009
Sales Volumes			
Oil and liquids sales (MBbls)	17,872	16,769	17,560
Gas (MMcf)			
Production	111,577	95,047	78,184
Used as fuel	2,108	1,954	2,358
Sales	109,469	93,093	75,826
MBOE			
Production	36,468	32,610	30,591
Sales	36,117	32,285	30,198
Daily Average Volumes			
Oil and liquids sales (Bbls)	48,964	45,943	48,110
Gas (Mcf)			
Production	305,691	260,402	214,203
Used as fuel	5,776	5,353	6,461
Sales	299,915	255,049	207,742
BOE			
Production	99,912	89,343	83,811
Sales	98,950	88,451	82,734
Unit Economics (in dollars)			
Average NYMEX Prices			
Oil	$ 95.11	$ 79.61	$ 62.09
Gas	4.04	4.38	3.97
Average Realized Sales Price			
Before Derivative Transactions			
Oil (per Bbl)	$ 85.53	$ 68.14	$ 51.43
Gas (per Mcf)	3.91	4.29	3.72
Per BOE	54.18	47.77	39.25
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 9.27	$ 8.13	$ 8.31
Steam gas costs	1.81	2.06	1.78
Electricity	1.14	1.33	1.45
Production and ad valorem taxes	1.53	0.91	1.28
Gathering and transportation	1.72	1.57	1.21
DD&A (oil and gas properties)	17.76	15.87	12.79

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

	Year Ended December 31,		
	2011	2010	2009
Oil derivatives			
Settlements	$ (60,392)	$ (67,917)	$ 141,297
Unwind of crude oil puts, swaps and collars	(2,935)	-	1,074,361
Natural gas derivatives	7,915	37,996	308,146
	$ (55,412)	$ (29,921)	$ 1,523,804

Comparison of Year Ended December 31, 2011 to Year Ended December 31, 2010

Oil and gas revenues. Oil and gas revenues increased $0.5 billion, to $2.0 billion for 2011 from $1.5 billion for 2010, primarily due to higher average realized oil prices and higher sales volumes partially offset by lower average realized gas prices.

Oil revenues increased $0.4 billion, to $1.5 billion for 2011 from $1.1 billion for 2010, reflecting higher average realized prices ($291.6 million) and higher sales volumes ($94.3 million). Our average realized price for oil increased $17.39 per Bbl to $85.53 per Bbl for 2011 from $68.14 per Bbl for 2010. The increase was primarily attributable to an increase in the NYMEX oil price, which averaged $95.11 per Bbl in 2011 versus $79.61 per Bbl in 2010. Oil sales volumes increased 3.1 MBbls per day to 49.0 MBbls per day in 2011 from 45.9 MBbls per day in 2010, primarily reflecting increased production from our Eagle Ford Shale properties and our Panhandle properties divested in December 2011, partially offset by a production decrease due to the December 2010 divestment of our U.S. Gulf of Mexico shallow water properties. Excluding the impact of our divestments in 2010 and 2011, production increased 3.2 MBbls per day in 2011.

Gas revenues increased $28.6 million, to $428.2 million in 2011 from $399.6 million in 2010, reflecting higher sales volumes ($64.1 million), partially offset by lower average realized prices ($35.5 million). Gas sales volumes increased 44.9 MMcf per day to 299.9 MMcf per day in 2011 from 255.0 MMcf per day in 2010, primarily reflecting increased production from our Haynesville Shale properties and our Panhandle properties divested in December 2011 partially offset by a production decrease due to the December 2010 divestment of our U.S. Gulf of Mexico shallow water properties. Excluding the impact of our divestments in 2010 and 2011, sales increased 73.4 MMcf per day in 2011. Our average realized price for gas was $3.91 per Mcf in 2011 compared to $4.29 per Mcf in 2010.

Lease operating expenses. Lease operating expenses increased $72.4 million, to $334.9 million in 2011 from $262.5 million in 2010, reflecting an increased number of producing wells at our Eagle Ford Shale properties and our Panhandle properties divested in December 2011 and higher scheduled repair and maintenance and well workovers primarily at our California properties.

Production and ad valorem taxes. Production and ad valorem taxes increased $25.8 million, to $55.2 million in 2011 from $29.4 million in 2010, reflecting increased production taxes in 2011 compared to 2010 due to increased production primarily from our Eagle Ford Shale properties and our Panhandle properties divested in December 2011 and production tax abatements recorded in 2010. The increase in ad valorem taxes is primarily at our California properties.

Gathering and transportation expenses. Gathering and transportation expenses increased $11.4 million, to $62.1 million in 2011 from $50.7 million in 2010, primarily reflecting an increase in production from our Haynesville Shale properties, our Panhandle properties divested in December 2011 and our Eagle Ford Shale properties, partially offset by a decrease due to the December 2010 divestment of our U.S. Gulf of Mexico shallow water properties.

General and administrative expense. G&A expense decreased $2.4 million, to $134.0 million in 2011 from $136.4 million in 2010, primarily due to lower franchise and other taxes and stock-based compensation expense, partially offset by costs attributable to increased headcount.

Depreciation, depletion and amortization. DD&A expense increased $131.1 million, to $664.5 million in 2011 from $533.4 million in 2010. The increase is attributable to our oil and gas depletion, primarily due to increased production ($68.5 million) and a higher per unit rate ($61.7 million). Our oil and gas unit of production rate increased to $17.76 per BOE in 2011 compared to $15.87 per BOE in 2010.

Interest expense. Interest expense increased $54.6 million, to $161.3 million in 2011 from $106.7 million in 2010, primarily due to greater average debt outstanding partially offset by lower average interest rates. Interest expense is net of interest capitalized on oil and natural gas properties not subject to amortization but in the process of development. We capitalized $117.4 million and $130.9 million of interest in 2011 and 2010, respectively.

Debt extinguishment costs. During 2011, we recognized $121.0 million of debt extinguishment costs in connection with the retirement of portions of our 7¾% Senior Notes, 10% Senior Notes and 7% Senior Notes. In connection with the reduction in the borrowing base on our senior revolving credit facility, we recorded $1.2 million of debt extinguishment costs in 2010.

Gain (loss) 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 a payment to or receiving a payment from the counterparty.

We recognized an $82.0 million gain related to mark-to-market derivative contracts in 2011, which was primarily associated with an increase in fair value of our 2012 and 2013 natural gas derivative contracts and our 2012 crude oil derivative contracts due to lower forward prices. In 2010, we recognized a $60.7 million loss related to mark-to-market derivative contracts.

Loss on investment measured at fair value. At December 31, 2011, we owned 51.0 million shares of McMoRan common stock. 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 recognized as loss on investment measured at fair value in our income statement.

We recognized a $52.7 million loss in 2011 related to our McMoRan investment, which was primarily associated with a decrease in McMoRan's stock price, partially offset by a lower discount to reflect certain limitations on the marketability of the shares.

Income taxes. Our 2011 income tax expense was $134.3 million, reflecting an annual effective tax rate of 39%, as compared with an income tax expense of $100.7 million and an effective tax rate of 49% for 2010. Variances in our annual effective tax rate from the 35% federal statutory for 2011 resulted primarily from the tax effects of permanent differences including expenses that are not deductible because of IRS limitations, state income taxes and changes to our balance of unrecognized tax positions. Variances in our annual effective tax rate from the 35% federal statutory rate for 2010 resulted primarily from the tax effects of permanent differences including expenses that are not deductible because of IRS limitations, state income taxes, tax and financial reporting differences related to non-cash compensation, changes to our balance of unrecognized tax positions and foreign operations.

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 for 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 per Bbl 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 is 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 interest capitalized 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.

Gain (loss) 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.

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, including those counterparties who may have exposure to certain European sovereign debt. These market conditions may adversely affect our liquidity by limiting our ability to access the capital and credit markets.

Our primary sources of liquidity are cash generated from our operations, our senior revolving credit facility and periodic public offerings of debt and equity. At December 31, 2011, we had approximately $663.8 million available for future secured borrowings under our senior revolving credit facility, which had commitments and a borrowing base of $1.4 billion and $1.8 billion, respectively. In February 2012, our borrowing base was increased from $1.8 billion to $2.3 billion until the next scheduled redetermination date on or before May 1, 2013. The commitments remained unchanged at $1.4 billion.

Under the terms of our 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.

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, 2011, the commitments are from a diverse syndicate of 21 lenders and no single lender's commitment represented more than 7% of the total commitments.

During the fourth quarter of 2011, we improved our liquidity position by reducing our future interest costs and extending the average maturity of our senior notes by issuing $1.0 billion of 6¾% Senior Notes that mature in 2022 and retiring approximately $1.3 billion of principal related to our senior notes with higher interest rates and nearer term maturities. See Financing Activities. We further improved our liquidity position by divesting our Texas Panhandle properties and our conventional natural gas South Texas properties. After the exercise of third party preferential rights and preliminary closing adjustments, we received approximately $735.8 million in cash upon the closing of these transactions. At December 31, 2011, we continue to have interests in approximately 50,000 gross acres at our Texas Panhandle properties. We expect to receive additional proceeds from future closings, as may be further modified for additional post-closing adjustments. The cash proceeds received from the 2011 divestments were primarily used to reduce indebtedness. Further, our investment in McMoRan was reclassified from long-term to current assets as the one year restriction to sell the shares ended on December 30, 2011.

Stock Repurchase Program. During the year ended December 31, 2011, we repurchased 10.4 million common shares at an average cost of $34.73 per share, totaling $361.7 million. In January 2012, we completed the purchase of an additional 2.4 million common shares at an average cost of $37.02 per share totaling $88.5 million.

Plains Offshore. In October 2011, we entered into a securities purchase agreement with EIG, pursuant to which we received $430.2 million of net cash proceeds in November 2011, upon closing of the transaction, in exchange for a 20% equity interest in Plains Offshore. The proceeds raised are expected to be used to fund Plains Offshore's share of capital investment in the Lucius oil field and the Phobos prospect exploratory drilling planned for 2012 and other activities. Under the agreement and upon closing of the transaction, Plains Offshore issued to the EIG Funds (i) 450,000 shares of Plains Offshore 8% convertible perpetual preferred stock and (ii) non-detachable warrants to purchase in aggregate 9,121,000 shares of Plains Offshore's common stock with an exercise price of $20 per share. In addition, Plains Offshore issued 87 million shares of Plains Offshore Class A common stock, which will be held in escrow until the conversion and cancellation of the preferred stock or the exercise of the warrants held by EIG. The preferred stock will pay quarterly cash dividends of 6% per annum and an additional 2% per annum dividend. The 2% dividend may be deferred and accumulated quarterly until paid. The shares of preferred stock also fully participate, on an as-converted basis at four times, in cash dividends distributed to any class of common stockholders of Plains Offshore.

The preferred holders have the right, at any time at their option, to convert any or all of such holder's preferred stock and exercise any of the associated non-detachable warrants into shares of Class A common stock of Plains Offshore, at an initial conversion/exercise price of $20 per share; the conversion price is subject to adjustment as a result of certain events. Additionally, at any time on or after the fifth anniversary of the closing date, we may exercise a call right to purchase all, but not less than all, of the outstanding preferred stock and associated non-detachable warrants for cash, at a price equal to the liquidation preference described below.

At any time after the fourth anniversary of the closing date, a majority of the preferred holders may cause Plains Offshore to use its commercially reasonable efforts to consummate an exit event. An exit event, as defined in the stockholders agreement, means, at the sole option of Plains Offshore (i) the purchase by us or the redemption by Plains Offshore of all the preferred stock, warrants and common stock held by the EIG Funds for the aggregate fair value thereof; (ii) a sale of Plains Offshore or a sale of all or substantially all of its assets, in each case in an arms' length transaction with a third party, at the highest price available after reasonable marketing efforts by Plains Offshore; or (iii) a qualified initial public offering. In the event that Plains Offshore fails to consummate an exit event prior to the applicable exit event deadline, the conversion price of the preferred stock and the exercise price of the warrants will immediately and automatically be adjusted such that all issued and outstanding shares of preferred stock on an as-converted basis taken together with shares of common stock issuable upon exercise of the warrants, in the aggregate, will constitute 49% of the common equity securities of Plains Offshore on a fully diluted basis. In addition, we will be required to purchase $300 million of junior preferred stock in Plains Offshore. If this occurs, our cash expenditures relating to the assets of Plains Offshore will approximate the cash contribution made by EIG to Plains Offshore. Plains Offshore must use the proceeds to repay its senior credit facility, which is discussed below.

In the event of liquidation of Plains Offshore, each preferred holder is entitled to receive the liquidation preference before any payment or distribution is made on any junior or common stock. A liquidation event includes any of the following events: (i) the liquidation, dissolution or winding up of Plains Offshore, whether voluntary or involuntary, (ii) a sale, consolidation or merger of Plains Offshore in which the stockholders immediately prior to such event do not own at least a majority of the outstanding shares of the surviving entity, or (iii) a sale or other disposition of all or substantially all of Plains Offshore's assets to a person other than us or our affiliates. The liquidation preference is equal to (i) the greater of (a) 1.25 times the initial offering price and (b) the sum of (1) the fair market value of the shares of common stock issuable upon conversion of the preferred stock and (2) the applicable tax adjustment amount, plus (ii) any accrued dividends and accumulated dividends.

The non-detachable warrants may be exercised at any time on the earlier of (i) the eighth anniversary of the original issue date or (ii) a termination event. Under the terms of the securities purchase agreement, a termination event is defined as the occurrence of any of (a) the conversion of the preferred stock, (b) the redemption of the preferred stock, (c) the repurchase by us or any of our affiliates of the preferred stock or (d) a liquidation event described above.

In November 2011, Plains Offshore also entered into a senior credit facility providing for $300 million of commitments to fund future capital costs beyond that already raised. See Financing Activities. At December 31, 2011, Plains Offshore had $300 million available for future secured borrowings.

Crude Oil Marketing Contract. In August 2011, we entered into a new marketing contract with ConocoPhillips effective January 1, 2012 that covers approximately 90% of our California production, extends the dedication from January 1, 2015 to January 1, 2023, and replaces the percent of NYMEX index pricing mechanism with a market-based pricing approach. Separately, we executed an agreement with a third party purchaser to sell a large portion of our Eagle Ford Shale crude oil using a Light Louisiana Sweet based pricing mechanism. Due to these new marketing contracts, we expect oil price realizations on a significant portion of our crude oil production to increase relative to WTI beginning in 2012.

Other Considerations. 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 2012 capital budget is approximately $1.6 billion, including capitalized interest and general and administrative expenses. We intend to fund our 2012 capital budget from internally generated funds and borrowings under our senior revolving credit facility, with the portion of our 2012 budget related to Plains Offshore being funded with cash on hand. 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, cash on hand and the Plains Offshore senior credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies, anticipated capital expenditures and preferred stock dividends of Plains Offshore. We have no near-term debt maturities. Our senior revolving credit facility matures on May 4, 2016 and the earliest maturity of our senior notes will occur on June 15, 2015.

Working Capital

At December 31, 2011, we had working capital of approximately $815.2 million, primarily due to the current asset classification of our investment in the McMoRan common shares and cash on hand from the Plains Offshore preferred stock transaction with EIG in November 2011. Our working capital fluctuates for various reasons, including the fair value of our investment, commodity derivative instruments and stock appreciation rights.

Financing Activities

Senior Revolving Credit Facility. As of December 31, 2011, our borrowing base is $1.8 billion and commitments are $1.4 billion. In May 2011, we entered into an amendment to our senior revolving credit facility, adjusting our borrowing rates and extending the maturity date to May 4, 2016. In connection with the EIG preferred stock private placement, we further amended our senior revolving credit facility in November 2011. See *Plains Offshore Senior Credit Facility.* The amendment requires, among other things, that we make a mandatory prepayment if the combined total borrowings under both our senior revolving credit facility and the Plains Offshore senior credit facility exceed the borrowing base, which remained at $1.8 billion. In connection with our divestments in December 2011, we further amended our senior revolving credit facility. The amendment provided for no reduction to our borrowing base. 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. In February 2012, our borrowing base was increased from $1.8 billion to $2.3 billion until the next scheduled redetermination date on or before May 1, 2013. The commitments remained unchanged at $1.4 billion. Additionally, our senior revolving credit facility contains a $250 million limit on letters of credit and a $50 million commitment for swingline loans. At December 31, 2011, we had $735.0 million in outstanding borrowings and $1.2 million in letters of credit outstanding under our senior revolving credit facility. The daily average outstanding balance for the quarter and year ended December 31, 2011 was $439.1 million and $411.2 million, respectively.

Amounts borrowed under our senior revolving credit facility, as amended, 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 1.50% to 2.50%; (ii) a variable amount ranging from 0.50% to 1.50% 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 1.50% to 2.50% for swingline loans. The additional variable amount of interest payable is based on the utilization rate as a percentage of (a) the total amount of funds borrowed under both our senior revolving credit facility and the Plains Offshore senior credit facility and (b) the borrowing base under our senior revolving credit facility. Letter of credit fees under our senior revolving credit facility are based on the utilization rate and range from 1.50% to 2.50%. Commitment fees range from 0.375% to 0.50% of amounts available for borrowing. The effective interest rate on our borrowings under our senior revolving credit facility was 2.08% at December 31, 2011.

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.

Plains Offshore Senior Credit Facility. The aggregate commitments of the lenders under the Plains Offshore senior credit facility are $300 million. The Plains Offshore senior credit facility contains a $50 million limit on letters of credit and matures on November 18, 2016. At December 31, 2011, Plains Offshore had no borrowings or letters of credit outstanding under its senior credit facility.

Amounts borrowed under the Plains Offshore senior credit facility bear an interest rate, at Plains Offshore's election, equal to either: (i) the Eurodollar rate, which is based on LIBOR, plus an additional variable amount ranging from 1.50% to 2.50%; (ii) a variable amount ranging from 0.50% to 1.50% 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%. The additional variable amount of interest payable is based on the utilization rate as a percentage of (a) the total amount of funds borrowed under both our senior revolving credit facility and the Plains Offshore senior credit facility and (b) the borrowing base under our senior revolving credit facility. Letter of credit fees under the Plains Offshore senior credit facility are based on the utilization rate and range from 1.50% to 2.50%. Commitment fees range from 0.375% to 0.50% of amounts available for borrowing.

The borrowings under the Plains Offshore senior credit facility are guaranteed on a senior basis by PXP and certain of our subsidiaries, and are secured on a *pari passu* basis by liens on the same collateral that secures PXP's senior revolving credit facility. The Plains Offshore senior credit facility contains certain affirmative and negative covenants, including limiting Plains Offshore's ability, among other things, to create liens, incur other indebtedness, make dividends (excluding dividends on preferred stock) or other distributions, make investments, change the nature of Plains Offshore's business and merge or consolidate, sell assets, enter into certain types of swap agreements and enter into certain transaction with affiliates, as well as other customary events of default, including a cross-default to PXP's senior revolving credit facility. If an event of default (as defined in our senior revolving credit facility) has occurred and is continuing under our senior revolving credit facility that has not been cured or waived by the lenders thereunder then the Plains Offshore lenders could accelerate and demand repayment of the Plains Offshore senior credit facility.

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, 2012, 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 14 days and all amounts outstanding are due and payable no later than June 1, 2012. 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, 2011. The daily average outstanding balance for the quarter and year ended December 31, 2011 was \$43.0 million and \$52.6 million, respectively. The weighted average interest rate on borrowings under our short-term credit facility was 1.5% for the years ended December 31, 2011 and 2010.

6¾% Senior Notes. In November 2011, we issued \$1 billion of 6¾% Senior Notes due 2022, or the 6¾% Senior Notes, at par. We received approximately \$984 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 6¾% Senior Notes on or after February 1, 2017 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to February 1, 2015 we may, at our option, redeem up to 35% of the 6¾% Senior Notes with the proceeds of certain equity offerings.

6⅝% Senior Notes. In March 2011, we issued \$600 million of 6⅝% Senior Notes due 2021, or the 6⅝% Senior Notes, at par. We received approximately \$590 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 6⅝% Senior Notes on or after May 1, 2016 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to May 1, 2014 we may, at our option, redeem up to 35% of the 6⅝% Senior Notes with the proceeds of certain equity offerings.

Cash Tender Offers for 7¾% Senior Notes, 10% Senior Notes and 7% Senior Notes. In December 2011, we made payments totaling \$542.2 million to retire \$520.7 million of the \$600 million outstanding principal amount of our 7¾% Senior Notes, \$429.5 million to retire \$380.1 million of the \$565 million outstanding principal amount of our 10% Senior Notes and \$442.1 million to retire \$423.1 million of the \$500 million outstanding principal amount of our 7% Senior Notes.

During 2011, we recognized \$121.0 million of debt extinguishment costs, including \$30.9 million of unamortized debt issue costs and original issue discount, in connection with our debt retirement transactions.

The 7¾% Senior Notes, 10% Senior Notes, 7% Senior Notes, 7⅝% Senior Notes due 2018, 8⅝% Senior Notes, 7⅝% Senior Notes due 2020, 6⅝% Senior Notes and 6¾% Senior Notes (together, the Senior Notes) are our general unsecured senior obligations. The Senior Notes are jointly and severally guaranteed by certain of our existing domestic subsidiaries. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the assets of that subsidiary guarantor; (ii) in connection with any sale or other disposition of all the capital stock of a subsidiary guarantor; (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of such subsidiary guarantor provided no default or event of default has occurred or is continuing; or (vi) at such time as such subsidiary guarantor does not have outstanding any guarantee of any of our or any of our subsidiary guarantor's indebtedness (other than the notes) in excess of $10.0 million in aggregate principal amount. 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 and the Plains Offshore's senior 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,		
	2011	2010	2009
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 1,110.8	$ 912.5	$ 499.0
Investing activities	(1,154.6)	(1,575.3)	(1,280.4)
Financing activities	456.5	667.4	471.3

Net cash provided by operating activities was $1.1 billion in 2011, $912.5 million in 2010 and $499.0 million in 2009. The increase in net cash provided by operating activities in 2011 primarily reflects higher operating income in 2011 as a result of higher average realized oil prices and a $63.9 million refund of income tax paid in prior years. 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.

Net cash used in investing activities of $1.2 billion in 2011 primarily reflects additions to oil and gas properties of approximately $1.8 billion partially offset by the divestment of our Panhandle and South Texas properties of approximately $735.8 million. 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 provided by financing activities of $456.5 million in 2011 primarily reflects the $1.6 billion of net proceeds from the 6¾% Senior Notes and the 6⅝% Senior Notes offerings, the $430.2 million in net proceeds from the issuance of Plains Offshore preferred stock and the net increase in borrowings under our senior revolving credit facility of $115.0 million, partially offset by the $1.3 billion redemption of long-term debt and $361.7 million for treasury stock purchases. 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 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.

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 2012, excluding acquisitions, is approximately $1.6 billion, including capitalized interest and general and administrative expenses. We believe that we have sufficient liquidity through our forecasted cash flow from operations, borrowing capacity under our senior revolving credit facility, cash on hand and the Plains Offshore senior credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies, anticipated capital expenditures and preferred stock dividends of Plains Offshore. 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

During the year ended December 31, 2011, we repurchased 10.4 million common shares at an average cost of $34.73 per share totaling $361.7 million.

In January 2012, we completed the purchase of an additional 2.4 million common shares at an average cost of $37.02 per share totaling $88.5 million. Subsequent to those purchases, our Board of Directors reset the authorization to $1.0 billion of PXP common stock, all of which is available for repurchase, and extended the program until January 2016.

Commitments and Contingencies

We had the following obligations at December 31, 2011 (in thousands):

	Total	2012	2013 and 2014	2015 and 2016	Thereafter
Long-term debt	$ 3,776,074	$ -	$ -	$ 999,173	$ 2,776,901
Interest on debt	1,951,675	223,467	488,185	457,894	782,129
Operating leases	102,138	15,016	28,173	24,038	34,911
Oil and gas and related activities	770,437	226,603	289,056	79,261	175,517
Asset retirement obligation	238,381	7,749	8,942	19,364	202,326
Commodity derivative contracts	68,291	18,209	50,082	-	-
Stock compensation awards	21,676	21,676	-	-	-
Tax uncertainties	8,708	6,614	480	-	1,614
Other obligations	24,894	10,250	9,761	2,074	2,809
	$ 6,962,274	$ 529,584	$ 874,679	$ 1,581,804	$ 3,976,207

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, 2011 remains outstanding to maturity with interest and commitment fees calculated at the rates in effect at December 31, 2011.

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

Oil and gas and related activities represent long-term obligations associated with exploration, development and production activities. We have entered into commitments for oil and gas gathering and transportation, drilling rig and oilfield services and the design, construction and operation of a produced water reclamation facility totaling approximately $456.1 million. Through our ownership in Lucius, we have a commitment of approximately $314.3 million for our share of certain long lead equipment orders and detailed engineering work.

Asset retirement obligations represent the estimated liability 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.

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, 2011 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 commitments 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 which we believe is customary in the industry for environmental matters, 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 2012 cash expenditures related to plugging, abandonment and remediation will be approximately $7.7 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, $82.6 million ($145.2 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 $86.1 million). To secure its abandonment obligations, the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2011, the escrow account had a balance of $17.7 million. The fair value of our guarantee at December 31, 2011, $0.7 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.

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 eight financial institutions that are counterparties for our derivative commodity contracts had a Standard & Poor's rating of A - or better as of December 31, 2011. 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.

The commitments under our senior revolving credit facility and the Plains Offshore senior credit facility are from a diverse syndicate of 21 lenders. At December 31, 2011, no single lender's commitments under both credit facilities combined represented more than 8% 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.

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. Approximately 95% of our 2011 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 and costs as of 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).

The 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 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 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. Conversely, in times of declining prices, ceiling test calculations may not result in an impairment.

At December 31, 2011, the ceiling with respect to our domestic oil and gas properties exceeded the net capitalized costs by 30% and we did not record an impairment.

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, 2011, we had approximately $2.4 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 57% of the costs not subject to amortization at December 31, 2011 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 2012, after the effect of our fourth quarter 2011 divestments, is expected to be $21.64 per BOE. Based on our estimated proved reserves and our net oil and gas properties subject to amortization at December 31, 2011: (i) a 5.0% increase in our costs subject to amortization would increase our DD&A rate by approximately $1.08 per BOE and (ii) a 5.0% negative revision to proved reserves would increase our DD&A rate by approximately $1.14 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 and ICE 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. The fair value amounts of our put and collar derivative instruments are estimated using an option-pricing model, which uses various inputs including NYMEX and ICE price quotations, volatilities, interest rates and contract terms. The fair value of our swap derivative instruments are estimated using a pricing model which has various inputs including NYMEX price quotations, 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 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 and/or interpolating 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.

Investment. We have elected to measure our equity investment in McMoRan at fair value, and the change in fair value of our investment is recognized as a gain or loss on investment measured at fair value in our income statement. We determine the fair value of our investment by discounting 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, implied volatility of the instrument, number of shares being valued, length of time that would be necessary to dispose of our investment, expected dividend and risk-free interest rates. The use of such models requires substantial judgment with respect to the inputs used to determine fair value.

At December 31, 2011, the McMoRan shares were valued at approximately $611.7 million, based on McMoRan's closing stock price of $14.55 on December 31, 2011, discounted to reflect certain limitations on the marketability of the shares.

For a further discussion concerning our risks related to equity prices and our equity investment in McMoRan, see Item 7A – Quantitative and Qualitative Disclosures about Market Risk – Equity 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 $49 million, $51 million and $61 million of stock-based compensation expense for the years ended December 31, 2011, 2010 and 2009, 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, 2011, goodwill totaled $535 million and represented approximately 5% 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.

In September 2011, the Financial Accounting Standards Board, or FASB, issued authoritative guidance which amends the rules for testing goodwill for impairment. Under the new rules, companies are permitted to make a qualitative assessment of a reporting unit's fair value prior to performing the two-step goodwill impairment test. If it is determined through the qualitative assessment that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. The qualitative assessment is optional, allowing companies to go directly to the quantitative assessment. As of December 31, 2011, we have elected to continue performing our annual goodwill impairment assessment under the quantitative two-step impairment test.

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.

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 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 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. We adopted the provisions of this standard effective January 1, 2011, 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 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. We adopted the provisions of this standard effective January 1, 2011, and it did not have a significant impact on our consolidated financial position, results of operations or cash flows.

In May 2011, the FASB issued authoritative guidance amending certain accounting and disclosure requirements related to fair value measurements. The guidance clarifies (i) the requirement that the highest and best use concept is only relevant for measuring nonfinancial assets, (ii) requirements to measure the fair value of instruments classified in shareholders' equity and (iii) the requirement to disclose quantitative information about the unobservable inputs used in a fair value measurement that is categorized within Level 3 of the fair value hierarchy. The guidance also (i) permits a reporting entity to measure the fair value of certain financial assets and liabilities managed in a portfolio at the price that would be received to sell a net asset position or transfer a net liability position for a particular risk, (ii) eliminates premiums or discounts related to size as a characteristic of the reporting entity's holding and (iii) expands disclosures for fair value measurement. The guidance is effective for interim and annual periods beginning after December 15, 2011. 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.

In June 2011, the FASB issued authoritative guidance to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. The guidance requires entities to report components of comprehensive income in either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. The guidance also requires entities to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statements where the components of net income and other comprehensive income are presented. In December 2011, the FASB issued further authoritative guidance deferring the requirements for entities to present on the face of the financial statements those reclassification adjustments for items that are reclassified from other comprehensive income to net income. The guidance reinstates the requirements for the presentation of reclassification adjustments on either the face of financial statements where comprehensive income is reported or in the notes to the financial statements. The requirements of both standards are effective for interim and annual periods beginning after December 15, 2011, with early adoption permitted. We adopted the provisions of the June 2011 guidance, excluding the requirements deferred in the December 2011 guidance, effective December 31, 2011 and these provisions require that we position our statement of comprehensive income consecutively to the income statement.

In September 2011, the FASB issued authoritative guidance permitting companies to make a qualitative assessment of a reporting unit's fair value prior to performing the two-step goodwill impairment test. If it is determined through the qualitative assessment that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. The qualitative assessment is optional, allowing companies to go directly to the quantitative assessment. The guidance is effective for interim and annual goodwill impairment tests performed in fiscal years beginning after December 15, 2011, with early adoption permitted. We perform our goodwill impairment test annually as of December 31. We adopted the provisions of this standard effective December 31, 2011 and elected to continue performing our annual goodwill impairment assessment under the quantitative two-step impairment test.

In December 2011, the FASB issued authoritative guidance requiring entities to disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as financial instruments and transactions subject to agreements similar to master netting arrangements. The additional disclosures will enable users of the financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. The guidance is effective for interim and annual periods beginning after January 1, 2013, and will primarily impact our disclosures associated with our commodity derivative instruments. We are currently evaluating the impact of this guidance.

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 6 – Commodity Derivative Contracts and Note 8 – Fair Value Measurements of Assets and Liabilities in the accompanying financial statements for a discussion of our derivative activities and fair value measurements.

In September 2011, and in response to our higher priced marketing contracts, we realigned our existing 2012 WTI crude oil put option spread contracts that had an $80 per barrel floor price with a $60 per barrel limit on 40,000 BOPD by acquiring 2012 Brent crude oil three-way collars that have a $100 per barrel floor price with an $80 per barrel limit and a weighted average ceiling price of $120 per barrel. Additionally, we converted 40,000 of the 160,000 MMBtu per day 2012 natural gas put option spread contracts that had a $4.30 per MMBtu floor price with a $3.00 per MMBtu limit to natural gas three-way collars that have a $4.30 per MMBtu floor price with a $3.00 per MMBtu limit and a weighted average ceiling price of $4.86 per MMBtu. We also acquired 2013 Brent crude oil put option spread contracts that have a $90 per barrel floor price with a $70 per barrel limit and weighted average deferred premium and interest of $6.237 per barrel on 22,000 BOPD. In December 2011, we entered into natural gas swap contracts at a weighted average price of $4.27 per MMBtu, on 110,000 MMBtu per day for 2013.

During the period from January 1, 2012 through February 22, 2012, we converted 5,000 of the 22,000 BOPD of Brent crude oil put option contracts in 2013 to three-way collars. These modified three-way collars have a floor price of $90 per barrel with a limit of $70 per barrel and a weighted average ceiling price of $126.08 and eliminates approximately $11 million of deferred premiums. Additionally, we entered into the following Brent oil derivatives for 2013 and 2014:

- Brent crude oil put option spread contracts on 13,000 BPOD for 2013 with a floor price of $100 per barrel and a limit of $80 per barrel.
- Brent three-way collars on 25,000 BOPD for 2013 that have a floor price of $100 per barrel with a limit of $80 per barrel and a weighted average ceiling price of $124.29 per barrel.
- Brent crude oil put option spread contracts on 20,000 BOPD for 2014 with a floor price of $90 per barrel and a limit of $70 per barrel.

In February 2012, we entered into natural gas swap contracts, at an average price of $4.16 per MMBtu, on 70,000 MMBtu per day for 2014.

As of February 22, 2012, 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					
2012					
Feb - Dec	Three-way collars [2]	40,000 Bbls	$100.00 Floor with an $80.00 Limit $120.00 Ceiling	-	Brent
2013					
Jan - Dec	Put options [3]	17,000 Bbls	$90.00 Floor with a $70.00 Limit	$6.253 per Bbl	Brent
Jan - Dec	Put options [4]	13,000 Bbls	$100.00 Floor with an $80.00 Limit	$6.800 per Bbl	Brent
Jan - Dec	Three-way collars [5]	25,000 Bbls	$100.00 Floor with an $80.00 Limit $124.29 Ceiling	-	Brent
Jan - Dec	Three-way collars [6]	5,000 Bbls	$90.00 Floor with a $70.00 Limit $126.08 Ceiling	-	Brent
2014					
Jan - Dec	Put options [3]	20,000 Bbls	$90.00 Floor with a $70.00 Limit	$6.555 per Bbl	Brent
Sales of Natural Gas Production					
2012					
Feb - Dec	Put options [7]	120,000 MMBtu	$4.30 Floor with a $3.00 Limit	$0.298 per MMBtu	Henry Hub
Feb - Dec	Three-way collars [8]	40,000 MMBtu	$4.30 Floor with a $3.00 Limit $4.86 Ceiling	-	Henry Hub
2013					
Jan - Dec	Swap contracts [9]	110,000 MMBtu	$4.27	-	Henry Hub
2014					
Jan - Dec	Swap contracts [9]	70,000 MMBtu	$4.16	-	Henry Hub

(1) The average strike prices do not reflect any premiums to purchase the put options.

(2) If the index price is less than the $100 per barrel floor, we receive the difference between the $100 per barrel floor and the index price up to a maximum of $20 per barrel. We pay the difference between the index price and $120 per barrel if the index price is greater than the $120 per barrel ceiling. If the index price is at or above $100 per barrel but at or below $120 per barrel, no cash settlement is required.

(3) If the index price is less than the $90 per barrel floor, we receive the difference between the $90 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 $90 per barrel, we pay only the option premium.

(4) If the index price is less than the $100 per barrel floor, we receive the difference between the $100 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 $100 per barrel, we pay only the option premium.

(5) If the index price is less than the $100 per barrel floor, we receive the difference between the $100 per barrel floor and the index price up to a maximum of $20 per barrel. We pay the difference between the index price and $124.29 per barrel if the index price is greater than the $124.29 per barrel ceiling. If the index price is at or above $100 per barrel but at or below $124.29 per barrel, no cash settlement is required.

(6) If the index price is less than the $90 per barrel floor, we receive the difference between the $90 per barrel floor and the index price up to a maximum of $20 per barrel. We pay the difference between the index price and $126.08 per barrel if the index price is greater than the $126.08 per barrel ceiling. If the index price is at or above $90 per barrel but at or below $126.08 per barrel, no cash settlement is required.

(7) 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.

(8) 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. We pay the difference between the index price and $4.86 per MMBtu if the index price is greater than the $4.86 per MMBtu ceiling. If the index price is at or above $4.30 per MMBtu but at or below $4.86 per MMBtu, no cash settlement is required.

(9) If the index price is less than the fixed price ($4.27 per MMBtu for the 2013 contracts and $4.16 per MMBtu for the 2014 contracts), we receive the difference between the fixed price and the index price. We pay the difference between the index price and the fixed price if the index price is greater than the fixed price.

For put options, we typically 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, is required. If we have less production than the volumes specified under the collar transaction when the floating price exceeds the ceiling price, we must make payments against which there are no offsetting revenues from production.

Under a swap contract, the counterparty is required to make a payment to us if the index price for any settlement period is less than the fixed price, and we are required to make a payment to the counterparty if the index price for any settlement period is greater than the fixed price. The amount we receive or pay is the difference between the index price and the fixed price multiplied by the contract volumes. If we have less production than the volumes specified under the swap transaction when the index price exceeds the fixed 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, 2011 and the change in fair value that would be expected from a 10% price increase or decrease is shown below (in millions):

		Effect of 10%	
	Fair Value Asset	Price Increase	Price Decrease
Crude oil puts	$ 48	$ (12)	$ 14
Crude oil collars	11	(81)	70
Natural gas collars	13	(3)	2
Natural gas puts	41	(6)	6
Natural gas swaps	13	(15)	16
	$ 126	$ (117)	$ 108

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 prices are higher than the NYMEX index level and our realized wellhead gas prices are lower than the NYMEX index level. See Items 1 and 2 – Business and Properties – Product Markets and Major Customers.

Approximately 20% of our 2011 crude oil production was sold under contracts that provide for NYMEX less a fixed price differential (as of December 31, 2011 the fixed price differential averaged $4.66 per barrel) with the remainder sold under contracts that provide for monthly field posted prices.

Approximately 50% 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, the Plains Offshore senior credit facility and our short-term credit facility. At December 31, 2011, $735.0 million was outstanding under our senior revolving credit facility at an effective interest rate of 2.08%. Based on the $735.0 million outstanding under our senior revolving credit facility at December 31, 2011, on an annualized basis a 1% change in the effective interest rate would result in a $7.4 million change in our interest costs. At December 31, 2011, no amounts were outstanding under the Plains Offshore senior credit facility or our short-term credit facility.

Equity Price Risk

We are exposed to market risk because we own an equity investment in McMoRan common stock. See Note 7 – Investment and Note 8 – Fair Value Measurements of Assets and Liabilities in the accompanying financial statements for a discussion of our equity investment. At December 31, 2011, the investment, comprised of 51.0 million shares of McMoRan common stock, was valued at approximately $611.7 million. A 10% change in the underlying equity market price per share would result in a $61.2 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 Rules 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, 2011 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, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2011 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

Not Applicable.

PART III

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

Information regarding our directors, executive officers and certain corporate governance items will be included in an amendment to this Form 10-K or in the proxy statement for the 2012 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2011, 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, 2012 and their business experience for the last five years.

Directors

James C. Flores, age 52, Chairman of the Board, President and Chief Executive Officer and a Director since September 2002. He has been Chairman of the Board and Chief Executive Officer of PXP since December 2002, and President since March 2004. He was also Chairman of the Board of Plains Resources, Inc., or Plains Resources (now known as Vulcan Energy Corporation), from May 2001 to June 2004 and is currently a director of Vulcan Energy 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 76, 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.

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 71, 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 71, 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 67, 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. He currently serves as a director of the National Energy Education and Development Project as well as the National Marine Sanctuary Foundation, where he is head of the Audit Committee.

Charles G. Groat, age 71, 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. Dr. Groat currently serves as a director on the board of The Water Institute of the Gulf.

John H. Lollar, age 73, 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 Chairman of the Compensation Committee and a member 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 52, 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 54, 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 49, 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 50, 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 serves on the board of McMoRan Exploration Co. 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 2012 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 2012 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 2012 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 2012 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	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 Company's Current Report on Form 8-K filed July 8, 2008, File No. 1-31470).
2.3	First Amendment to the Participation Agreement between Plains Exploration & Production Company, PXP Louisiana L.L.C., PXP Louisiana Operations LLC and Chesapeake Louisiana, L.P., dated February 20, 2009 (incorporated by reference to Exhibit 2.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-31470, or the 2008 10-K).
2.4	Second Amendment to the Participation Agreement among Plains Exploration & Production Company, PXP Louisiana L.L.C., PXP Louisiana Operations LLC and Chesapeake Louisiana, L.P., dated August 5, 2009 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 7, 2009, File No. 1-31470).
2.5*	Purchase and Sale Agreement dated as of November 3, 2011, and effective as of November 1, 2011, by and among Plains Exploration & Production Company, Pogo Producing Company LLC, Latigo Petroleum, Inc. and Linn Energy Holdings, LLC.
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 Second Amended and Restated Bylaws of Plains Exploration & Production Company, adopted as of September 14, 2011 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed September 16, 2011, File No. 1-31470).

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 the 7% Senior Notes) (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 the 7¾% Senior Notes) (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 the 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 10% Senior 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 8⅝% Senior 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 Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee (including form of the 7⅝% Senior 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 Twelfth Supplemental Indenture, dated as of March 29, 2011, 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 the 6⅝% Senior Notes) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed March 29, 2011, File No. 1-31470).

4.14 Thirteenth Supplemental Indenture, dated as of November 21, 2011, 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 the 6¾% Senior Notes) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed November 21, 2011, File No. 1-31470, or the November 21, 2011 Form 8-K).

4.15 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).

4.16 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).

4.17 Amendment No.2 to Amended and Restated Credit Agreement, dated as of May 4, 2011, 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 May 5, 2011, File No. 1-31470).

4.18 Omnibus Amendment No.3 to Amended and Restated Credit Agreement, dated as of November 17, 2011, among Plains Exploration & Production Company, the several banks and other financial institutions signatory thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 4.2 to the November 21, 2011 Form 8-K).

4.19	Amendment No.4, dated December 8, 2011, to the 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 December 9, 2011, File No. 1-31470).
4.20*	Form of Credit Agreement, dated November 18, 2011, among Plains Offshore Operations Inc., as borrower, each of the lenders that is a signatory thereto, and JPMorgan Chase Bank, N.A., as administrative agent.
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+	Plains Exploration & Production Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.7 to the 2007 10-K).
10.5+	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).
10.6+*	Form of Restricted Stock Unit Agreement under the 2002 Stock Incentive Plan.
10.7+	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).
10.8+	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).
10.9+	Form of Plains Restricted Stock Award Agreement under the 2004 Incentive Plan (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, File No. 1-31470).
10.10+*	Form of Restricted Stock Unit Agreement under the 2004 Stock Incentive Plan.
10.11+	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).
10.12+	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).
10.13+	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).

10.14+	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).
10.15+	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).
10.16+	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).
10.17+	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).
10.18+	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).
10.19+	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).
10.20	Form of Election for Director Deferral of Restricted Stock Awards (incorporated by reference to Exhibit 10.23 to the 2008 10-K).
10.21	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).
10.22+	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).
10.23+	Form of Plains Stock Appreciation Rights Agreement under the 2010 Incentive Plan (incorporated by reference to Exhibit 10.24 to the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 1-31470, or the 2010 10-K).
10.24+	Form of Plains Restricted Stock Award Agreement under the 2010 Incentive Plan (incorporated by reference to Exhibit 10.25 to the 2010 10-K).
10.25+*	Form of Restricted Stock Unit Agreement under the 2010 Incentive Award Plan.
10.26+	Restricted Stock Unit Agreement, effective as of November 4, 2010, between Plains Exploration & Production Company and James C. Flores (incorporated by reference to Exhibit 10.27 to the 2010 10-K).
10.27	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 the Company's Current Report on Form 8-K filed January 6, 2011, File No. 1-31470, or the January 6, 2011 Form 8-K).
10.28	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 the January 6, 2011 Form 8-K).

10.29#	Crude Oil Purchase Agreement dated January 1, 2012, between Plains Exploration & Production Company and ConocoPhillips Company (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q/A for the quarter ended June 30, 2011, File No. 1-31470).
10.30*	Plains Exploration & Production Company 2006 Incentive Plan.
10.31+*	Form of Plains Restricted Stock Unit Agreement under the 2006 Incentive Plan.
21.1*	List of Subsidiaries of Plains Exploration & Production Company.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Rule 13(a)-14(a)/15d-14(a) Certificate of the Chief Executive Officer.
31.2*	Rule 13(a)-14(a)/15d-14(a) Certificate of the Chief Financial Officer.
32.1*	Section 1350 Certificate of the Chief Executive Officer.
32.2*	Section 1350 Certificate of the Chief Financial Officer.
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.
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.
\+ Management contracts or compensatory plans or arrangements.
\# Pursuant to a request for confidential treatment, portions of this exhibit have been redacted from the publicly filed document and have been furnished separately to the SEC.

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 23, 2012	/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 23, 2012	/s/ James C. Flores
	James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: February 23, 2012	/s/ Isaac Arnold, Jr.
	Isaac Arnold, Jr., Director
Date: February 23, 2012	/s/ Alan R. Buckwalter, III
	Alan R. Buckwalter, III, Director
Date: February 23, 2012	/s/ Jerry L. Dees
	Jerry L. Dees, Director
Date: February 23, 2012	/s/ Tom H. Delimitros
	Tom H. Delimitros, Director
Date: February 23, 2012	/s/ Thomas A. Fry, III
	Thomas A. Fry, III, Director
Date: February 23, 2012	/s/ Charles G. Groat
	Charles G. Groat, Director
Date: February 23, 2012	/s/ John H. Lollar
	John H. Lollar, Director
Date: February 23, 2012	/s/ Winston M. Talbert
	Winston M. Talbert, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 23, 2012	/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, comprehensive income, equity and cash flows present fairly, in all material respects, the financial position of Plains Exploration & Production Company and its subsidiaries (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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, 2011, 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.

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 23, 2012

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

	December 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	$ 419,098	$ 6,434
Accounts receivable	302,675	269,024
Commodity derivative contracts	50,964	-
Inventories	20,173	24,406
Investment	611,671	-
Deferred income taxes	20,723	74,086
Prepaid expenses and other current assets	16,073	28,937
	1,441,377	402,887
Property and Equipment, at cost		
Oil and natural gas properties - full cost method		
Subject to amortization	12,016,252	9,975,056
Not subject to amortization	2,409,449	3,304,554
Other property and equipment	145,959	137,150
	14,571,660	13,416,760
Less allowance for depreciation, depletion, amortization and impairment	(6,846,365)	(6,196,008)
	7,725,295	7,220,752
Goodwill	535,140	535,144
Commodity Derivative Contracts	12,678	-
Investment	-	664,346
Other Assets	76,982	71,808
	$ 9,791,472	$ 8,894,937
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 385,231	$ 284,628
Commodity derivative contracts	3,761	52,971
Royalties and revenues payable	97,095	70,990
Stock appreciation rights	21,676	10,603
Interest payable	39,342	49,127
Other current liabilities	79,081	65,370
	626,186	533,689
Long-Term Debt	3,760,952	3,344,717
Other Long-Term Liabilities		
Asset retirement obligation	230,633	225,571
Commodity derivative contracts	823	24,740
Other	15,749	28,205
	247,205	278,516
Deferred Income Taxes	1,461,897	1,355,050
Commitments and Contingencies (Note 12)		
Equity		
Stockholders' equity		
Common stock, $0.01 par value, 250.0 million shares authorized, 143.9 million shares issued at December 31, 2011 and 2010	1,439	1,439
Additional paid-in capital	3,434,928	3,427,869
Retained earnings	337,991	148,620
Treasury stock, at cost, 13.3 million shares and 3.8 million shares at December 31, 2011 and 2010, respectively	(509,722)	(194,963)
	3,264,636	3,382,965
Noncontrolling interest		
Preferred stock of subsidiary	430,596	-
	3,695,232	3,382,965
	$ 9,791,472	$ 8,894,937

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2011	2010	2009
Revenues			
Oil sales	$ 1,528,656	$ 1,142,760	$ 903,146
Gas sales	428,220	399,607	281,978
Other operating revenues	7,612	2,228	2,006
	1,964,488	1,544,595	1,187,130
Costs and Expenses			
Lease operating expenses	334,923	262,533	250,916
Steam gas costs	65,482	66,449	53,801
Electricity	41,242	42,794	43,891
Production and ad valorem taxes	55,225	29,446	38,708
Gathering and transportation expenses	62,103	50,680	36,651
General and administrative	134,044	136,437	144,586
Depreciation, depletion and amortization	664,478	533,416	407,248
Impairment of oil and gas properties	-	59,475	-
Accretion	17,177	17,702	14,332
Legal recovery	-	(8,423)	(87,272)
Other operating (income) expense	(735)	(4,130)	2,136
	1,373,939	1,186,379	904,997
Income from Operations	590,549	358,216	282,133
Other (Expense) Income			
Interest expense	(161,316)	(106,713)	(73,811)
Debt extinguishment costs	(120,954)	(1,189)	(12,093)
Gain (loss) on mark-to-market derivative contracts	81,981	(60,695)	(7,017)
Loss on investment measured at fair value	(52,675)	(1,551)	-
Other income	3,356	15,942	27,968
Income Before Income Taxes	340,941	204,010	217,180
Income tax benefit (expense)			
Current	25,952	93,090	(45,091)
Deferred	(160,214)	(193,835)	(35,784)
Net Income	206,679	$ 103,265	$ 136,305
Net income attributable to noncontrolling interest in the form of preferred stock of subsidiary	(1,400)		
Net Income Attributable to Common Stockholders	$ 205,279		
Earnings per Common Share			
Basic	$ 1.45	$ 0.74	$ 1.10
Diluted	$ 1.44	$ 0.73	$ 1.09
Weighted Average Common Shares Outstanding			
Basic	141,227	140,438	124,405
Diluted	142,999	141,897	125,288

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2011	2010	2009
Net Income	$ 206,679	$ 103,265	$ 136,305
Other Comprehensive Income			
Pension liability adjustment	-	-	1,094
Pension related tax expense	-	-	(410)
	-	-	684
Comprehensive Income	206,679	$ 103,265	$ 136,989
Comprehensive income attributable to noncontrolling interest in the form of preferred stock of subsidiary	(1,400)		
Comprehensive Income Attributable to Common Stockholders	$ 205,279		

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 206,679	$ 103,265	$ 136,305
Items not affecting cash flows from operating activities			
Depreciation, depletion and amortization	664,478	533,416	407,248
Impairment of oil and gas properties	-	59,475	-
Accretion	17,177	17,702	14,332
Deferred income tax expense	160,214	193,835	35,784
Debt extinguishment costs	2,844	1,189	12,093
(Gain) loss on mark-to-market derivative contracts	(81,981)	60,695	7,017
Loss on investment measured at fair value	52,675	1,551	-
Non-cash compensation	49,193	50,875	60,490
Other non-cash items	(5,559)	1,043	6,950
Change in assets and liabilities from operating activities			
Accounts receivable and other assets	(62,389)	(41,604)	(26,600)
Inventories	4,660	(4,502)	760
Accounts payable and other liabilities	59,086	(31,351)	(47,106)
Income taxes receivable/payable	43,678	(33,119)	(108,227)
Net cash provided by operating activities	1,110,755	912,470	499,046
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to oil and gas properties	(1,783,304)	(1,048,858)	(1,628,357)
Acquisition of oil and gas properties	(40,515)	(554,685)	(1,159,939)
Proceeds from sales of oil and gas properties and related assets, net of costs and expenses	736,228	73,965	-
Derivative settlements	(55,412)	(29,921)	1,522,412
Additions to other property and equipment	(13,140)	(15,809)	(14,677)
Other	1,552	-	162
Net cash used in investing activities	(1,154,591)	(1,575,308)	(1,280,399)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from revolving credit facilities	6,305,300	3,332,610	3,513,325
Repayments of revolving credit facilities	(6,190,300)	(2,942,610)	(4,588,325)
Principal payments of long-term debt	(1,295,737)	-	-
Proceeds from issuance of Senior Notes	1,600,000	300,000	916,439
Costs incurred in connection with financing arrangements	(30,239)	(22,771)	(19,556)
Purchase of treasury stock	(361,729)	-	-
Net proceeds from issuance of noncontrolling interest in the form of preferred stock of subsidiary	430,246	-	-
Derivative settlements	-	-	1,392
Issuance of common stock	-	-	648,005
Distributions to holders of noncontrolling interest in the form of preferred stock of subsidiary	(1,050)	-	-
Other	9	184	57
Net cash provided by financing activities	456,500	667,413	471,337
Net increase (decrease) in cash and cash equivalents	412,664	4,575	(310,016)
Cash and cash equivalents, beginning of period	6,434	1,859	311,875
Cash and cash equivalents, end of period	$ 419,098	$ 6,434	$ 1,859

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY
CONSOLIDATED STATEMENTS OF EQUITY
(share and dollar amounts in thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Amount	Total Stockholders' Equity	Noncontrolling Interest in the Form of Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2008	112,874	$1,129	$2,739,625	$ (85,101)	$(684)	(5,283)	$ (277,689)	$2,377,280		$ 2,377,280
Net income	-	-	-	136,305	-	-	-	136,305		136,305
Issuance of common stock	31,050	310	647,695	-	-	-	-	648,005		648,005
Restricted stock awards	-	-	36,630	-	-	-	-	36,630		36,630
Issuance of treasury stock for restricted stock awards	-	-	(42,416)	-	-	764	42,416	-		-
Other comprehensive income	-	-	-	-	684	-	-	684		684
Exercise of stock options and other	-	-	32	-	-	7	45	77		77
Balance at December 31, 2009	143,924	1,439	3,381,566	51,204	-	(4,512)	(235,228)	3,198,981		3,198,981
Net income	-	-	-	103,265	-	-	-	103,265		103,265
Restricted stock awards	-	-	80,515	-	-	-	-	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		204
Balance at December 31, 2010	143,924	1,439	3,427,869	148,620	-	(3,764)	(194,963)	3,382,965		3,382,965
Net income	-	-	-	205,279	-	-	-	205,279	$ 1,400	206,679
Restricted stock awards	-	-	38,092	-	-	-	-	38,092		38,092
Treasury stock purchases	-	-	-	-	-	(10,415)	(361,729)	(361,729)		(361,729)
Issuance of treasury stock for restricted stock awards	-	-	(31,033)	(15,857)	-	876	46,890	-		-
Issuance of noncontrolling interest in the form of preferred stock of subsidiary	-	-	-	-	-	-	-	-	430,246	430,246
Distributions to holders of noncontrolling interest in the form of preferred stock of subsidiary	-	-	-	-	-	-	-	-	(1,050)	(1,050)
Exercise of stock options and other	-	-	-	(51)	-	1	80	29	-	29
Balance at December 31, 2011	143,924	$1,439	$3,434,928	$ 337,991	$ -	(13,302)	$(509,722)	$3,264,636	$430,596	$3,695,232

See notes to consolidated financial statements

PLAINS EXPLORATION & PRODUCTION COMPANY
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 consolidated subsidiaries. We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. 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) noncontrolling interest in the form of preferred stock of subsidiary; (7) income taxes; (8) accrued assets and liabilities; (9) stock-based compensation; (10) asset retirement obligations and (11) 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 18 – 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 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, or WTI, for oil and the Henry Hub spot price for gas. 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 third quarter of 2011, we determined not to develop the Friesian prospect and the lease terminated by its terms. The accumulated costs of approximately $460 million associated with the project were transferred to the full cost pool.

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 terminated 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, 2011 and 2010 included $7.0 million and $4.3 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, 2011 and 2010, inventory consisted of the following (in thousands):

	December 31,	
	2011	2010
Oil	$ 7,075	$ 6,744
Materials and supplies	13,098	17,662
	$ 20,173	$ 24,406

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 some portion or all of 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 11 – 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, 2011 or 2010.

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 6 – 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 7 – Investment and Note 8 – 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 8 – 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, 2011, goodwill totaled $535 million and represented approximately 5% 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.

In September 2011, the Financial Accounting Standards Board, or FASB, issued authoritative guidance which amends the rules for testing goodwill for impairment. Under the new rules, companies are permitted to make a qualitative assessment of a reporting unit's fair value prior to performing the two-step goodwill impairment test. If it is determined through the qualitative assessment that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. The qualitative assessment is optional, allowing companies to go directly to the quantitative assessment. As of December 31, 2011, we have elected to continue performing our annual goodwill impairment assessment under the quantitative two-step impairment test.

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.

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 equity.

Noncontrolling Interest in the Form of Preferred Stock of Subsidiary. Noncontrolling interest in the form of preferred stock of subsidiary represents third-party ownership in the net assets of our consolidated subsidiary Plains Offshore Operations Inc., or Plains Offshore, in the form of convertible perpetual preferred stock and associated non-detachable warrants, which are classified as permanent equity in our consolidated balance sheet since redemption for cash of the preferred stock is within our control. See Note 4 – Noncontrolling Interest in the Form of Preferred Stock of Subsidiary.

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 10 – 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 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. We adopted the provisions of this standard effective January 1, 2011, 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 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. We adopted the provisions of this standard effective January 1, 2011, and it did not have a significant impact on our consolidated financial position, results of operations or cash flows.

In May 2011, the FASB issued authoritative guidance amending certain accounting and disclosure requirements related to fair value measurements. The guidance clarifies (i) the requirement that the highest and best use concept is only relevant for measuring nonfinancial assets, (ii) requirements to measure the fair value of instruments classified in shareholders' equity and (iii) the requirement to disclose quantitative information about the unobservable inputs used in a fair value measurement that is categorized within Level 3 of the fair value hierarchy. The guidance also (i) permits a reporting entity to measure the fair value of certain financial assets and liabilities managed in a portfolio at the price that would be received to sell a net asset position or transfer a net liability position for a particular risk, (ii) eliminates premiums or discounts related to size as a characteristic of the reporting entity's holding and (iii) expands disclosures for fair value measurement. The guidance is effective for interim and annual periods beginning after December 15, 2011. 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.

In June 2011, the FASB issued authoritative guidance to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. The guidance requires entities to report components of comprehensive income in either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. The guidance also requires entities to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statements where the components of net income and other comprehensive income are presented. In December 2011, the FASB issued further authoritative guidance deferring the requirements for entities to present on the face of the financial statements those reclassification adjustments for items that are reclassified from other comprehensive income to net income. The guidance reinstates the requirements for the presentation of reclassification adjustments on either the face of financial statements where comprehensive income is reported or in the notes to the financial statements. The requirements of both standards are effective for interim and annual periods beginning after December 15, 2011, with early adoption permitted. We adopted the provisions of the June 2011 guidance, excluding the requirements deferred in the December 2011 guidance, effective December 31, 2011 and these provisions require that we position our statement of comprehensive income consecutively to the income statement.

In September 2011, the FASB issued authoritative guidance permitting companies to make a qualitative assessment of a reporting unit's fair value prior to performing the two-step goodwill impairment test. If it is determined through the qualitative assessment that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. The qualitative assessment is optional, allowing companies to go directly to the quantitative assessment. The guidance is effective for interim and annual goodwill impairment tests performed in fiscal years beginning after December 15, 2011, with early adoption permitted. We perform our goodwill impairment test annually as of December 31. We adopted the provisions of this standard effective December 31, 2011 and elected to continue performing our annual goodwill impairment assessment under the quantitative two-step impairment test.

In December 2011, the FASB issued authoritative guidance requiring entities to disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as financial instruments and transactions subject to agreements similar to master netting arrangements. The additional disclosures will enable users of the financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. The guidance is effective for interim and annual periods beginning after January 1, 2013, and will primarily impact our disclosures associated with our commodity derivative instruments. We are currently evaluating the impact of this guidance.

Note 2 — Acquisitions

Eagle Ford Shale

During the fourth quarter of 2010, we completed the acquisition of approximately 60,000 net acres in the Eagle Ford Shale 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 our Eagle Ford Shale 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 our Eagle Ford Shale 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. During the first half of 2011, the reverse like-kind arrangements pursuant to IRC Section 1031 were concluded prior to the completion of a like-kind exchange involving any disposition of PXP properties. As a result, the related Eagle Ford Shale properties were transferred from PXP Operations LLC, which was reported as a Non-Guarantor Subsidiary, to PXP, which is reported as Issuer, and the outstanding notes between PXP Operations LLC and PXP were settled. See Note 16 – Consolidating Financial Statements.

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 and we 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 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. 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.

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.

Note 3 — Divestments

Panhandle and South Texas Properties

In December 2011, we completed the divestment of our Texas Panhandle properties to Linn Energy, LLC. After the exercise of third party preferential rights and preliminary closing adjustments, we received approximately $554.8 million in cash. At December 31, 2011, we continue to have interests in approximately 50,000 gross leasehold acres. We expect to receive additional proceeds from future closings, as may be further modified for additional post-closing adjustments. The cash proceeds received, net of approximately $6.2 million in transaction costs, were primarily used to reduce indebtedness. Our aggregate working interest in the Texas Panhandle properties generated total sales volumes of approximately 84 MMcfe per day during the third quarter of 2011 and had 263 Bcfe of estimated proved reserves as of December 31, 2010. The transaction was effective November 1, 2011.

In December 2011, we completed the divestment of all our working interests in our South Texas conventional natural gas properties to a third party. After preliminary closing adjustments, we received $181.0 million in cash. The cash proceeds received were primarily used to reduce indebtedness. The transaction was effective September 1, 2011.

The proceeds from the 2011 sales of oil and gas properties were recorded as reductions to capitalized costs pursuant to full cost accounting rules.

Gulf of Mexico

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 limitations 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.

Note 4 — Noncontrolling Interest in the Form of Preferred Stock of Subsidiary

In October 2011, we entered into a securities purchase agreement with EIG Global Energy Partners, or EIG, pursuant to which we received $430.2 million of net cash proceeds in November 2011, upon closing of the transaction, in exchange for a 20% equity interest in Plains Offshore. Plains Offshore holds all of our oil and natural gas properties and assets located in the United States Gulf of Mexico in water depths of 500 feet or more. The proceeds raised are expected to be used to fund Plains Offshore's share of capital investment in the Lucius oil field and the Phobos prospect exploratory drilling planned for 2012 and other activities. Under the agreement and upon closing of the transaction, Plains Offshore issued to EIG managed funds and accounts, or the EIG Funds (i) 450,000 shares of Plains Offshore 8% convertible perpetual preferred stock and (ii) non-detachable warrants to purchase in aggregate 9,121,000 shares of Plains Offshore's common stock with an exercise price of $20 per share. In addition, Plains Offshore issued 87 million shares of Plains Offshore Class A common stock, which will be held in escrow until the conversion and cancellation of the preferred stock or the exercise of the warrants held by EIG. The preferred stock will pay quarterly cash dividends of 6% per annum and an additional 2% per annum dividend. The 2% dividend may be deferred and accumulated quarterly until paid. The shares of preferred stock also fully participate, on an as-converted basis at four times, in cash dividends distributed to any class of common stockholders of Plains Offshore.

The preferred holders have the right, at any time at their option, to convert any or all of such holder's preferred stock and exercise any of the associated non-detachable warrants into shares of Class A common stock of Plains Offshore, at an initial conversion/exercise price of $20 per share; the conversion price is subject to adjustment as a result of certain events. Furthermore, under the terms of the securities purchase agreement, Plains Offshore has the right to convert all or a portion of the outstanding shares of preferred stock if certain events occur more than 180 days after an initial public offering or a qualified public offering of Plains Offshore. We have a right to purchase shares of preferred stock, common stock and warrants under certain circumstances in order to permit the consolidation of Plains Offshore for federal income tax purposes. Additionally, at any time on or after the fifth anniversary of the closing date, we may exercise a call right to purchase all, but not less than all, of the outstanding preferred stock and associated non-detachable warrants for cash, at a price equal to the liquidation preference described below.

At any time after the fourth anniversary of the closing date, a majority of the preferred holders may cause Plains Offshore to use its commercially reasonable efforts to consummate an exit event. An exit event, as defined in the stockholders agreement, means, at the sole option of Plains Offshore (i) the purchase by us or the redemption by Plains Offshore of all the preferred stock, warrants and common stock held by the EIG Funds for the aggregate fair value thereof, or the repurchase option; (ii) a sale of Plains Offshore or a sale of all or substantially all of its assets, in each case in an arms' length transaction with a third party, at the highest price available after reasonable marketing efforts by Plains Offshore; or (iii) a qualified initial public offering. Under the repurchase option, the form of consideration shall be at our sole discretion, which could be (a) cash, (b) our shares of registered, freely-tradable common stock (valued at 95% of the average closing sale price) or (c) a combination of (a) and (b) above. In the event that Plains Offshore fails to consummate an exit event prior to the applicable exit event deadline, the conversion price of the preferred stock and the exercise price of the warrants will immediately and automatically be adjusted such that all issued and outstanding shares of preferred stock on an as-converted basis taken together with shares of common stock issuable upon exercise of the warrants, in the aggregate, will constitute 49% of the common equity securities of Plains Offshore on a fully diluted basis. In addition, we will be required to purchase $300 million of junior preferred stock in Plains Offshore. If this occurs, our cash expenditures relating to the assets of Plains Offshore will approximate the cash contribution made by EIG to Plains Offshore. Plains Offshore must use the proceeds to repay its senior credit facility. See Note 5 – Long-Term Debt.

The preferred holders are entitled to vote on all matters on which common stockholders are entitled to vote. Each holder is entitled to one vote for each share that such holder would be entitled to receive if such holder's shares of preferred stock were converted into common shares on the record date set by the board of directors for such vote. Prior to an initial public offering, the holders have preemptive rights with respect to certain issuances of equity securities of Plains Offshore. In the event that we or any of our affiliates intend to transfer any of their common shares to an unaffiliated third party purchaser, each other equity holder will have certain tag along rights.

In the event of liquidation of Plains Offshore, each preferred holder is entitled to receive the liquidation preference before any payment or distribution is made on any junior or common stock. A liquidation event includes any of the following events: (i) the liquidation, dissolution or winding up of Plains Offshore, whether voluntary or involuntary, (ii) a sale, consolidation or merger of Plains Offshore in which the stockholders immediately prior to such event do not own at least a majority of the outstanding shares of the surviving entity, or (iii) a sale or other disposition of all or substantially all of Plains Offshore's assets to a person other than us or our affiliates. The liquidation preference is equal to (i) the greater of (a) 1.25 times the initial offering price and (b) the sum of (1) the fair market value of the shares of common stock issuable upon conversion of the preferred stock and (2) the applicable tax adjustment amount, plus (ii) any accrued dividends and accumulated dividends.

The non-detachable warrants may be exercised at any time on the earlier of (i) the eighth anniversary of the original issue date or (ii) a termination event. Under the terms of the securities purchase agreement, a termination event is defined as the occurrence of any of (a) the conversion of the preferred stock, (b) the redemption of the preferred stock, (c) the repurchase by us or any of our affiliates of the preferred stock or (d) a liquidation event described above. The non-detachable warrants are considered to be embedded instruments for accounting purposes as the instrument cannot be both legally detached and separately exercised from the host preferred stock, nor can the non-detachable warrants be transferred or sold without also transferring the ownership in the preferred stock.

The preferred stock of Plains Offshore is classified as permanent equity in our consolidated balance sheet since redemption for cash of the preferred interests is within our and Plains Offshore's control.

In December 2011, Plains Offshore announced a quarterly dividend on the preferred stock of $1.4 million, or $3.11 per share of preferred stock, 75% of which was paid in cash with the remaining 25% deferred.

Note 5 — Long-Term Debt

At December 31, 2011 and 2010, long-term debt consisted of (in thousands):

	December 31,	
	2011	2010
Senior revolving credit facility	$ 735,000	$ 620,000
Plains Offshore senior credit facility	-	-
7¾% Senior Notes due 2015	79,281	600,000
10% Senior Notes due 2016 (1)	175,385	530,812
7% Senior Notes due 2017	76,901	500,000
7⅝% Senior Notes due 2018	400,000	400,000
8⅝% Senior Notes due 2019 (2)	394,385	393,905
7⅝% Senior Notes due 2020	300,000	300,000
6⅝% Senior Notes due 2021	600,000	-
6¾% Senior Notes due 2022	1,000,000	-
	$ 3,760,952	$ 3,344,717

(1) The amount is net of unamortized discount of $9.5 million and $34.2 million at December 31, 2011 and December 31, 2010, respectively.

(2) The amount is net of unamortized discount of $5.6 million and $6.1 million at December 31, 2011 and December 31, 2010, respectively.

As of December 31, 2011, aggregate total maturities of long-term debt in the next five years are $999.2 million, including $79.3 million in 2015 and $919.9 million in 2016.

Senior Revolving Credit Facility. As of December 31, 2011, our borrowing base is $1.8 billion and commitments are $1.4 billion. In May 2011, we entered into an amendment to our senior revolving credit facility, adjusting our borrowing rates and extending the maturity date to May 4, 2016. In connection with the EIG preferred stock private placement, we further amended our senior revolving credit facility in November 2011. See *Plains Offshore Senior Credit Facility.* The amendment requires, among other things, that we make a mandatory prepayment if the combined total borrowings under both our senior revolving credit facility and the Plains Offshore senior credit facility exceed the borrowing base, which remained at $1.8 billion. In connection with our divestments in December 2011, we further amended our senior revolving credit facility. The amendment provided for no reduction to our borrowing base. 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 and a $50 million commitment for swingline loans. At December 31, 2011, we had $1.2 million in letters of credit outstanding under our senior revolving credit facility.

Amounts borrowed under our senior revolving credit facility, as amended, 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 1.50% to 2.50%; (ii) a variable amount ranging from 0.50% to 1.50% 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 1.50% to 2.50% for swingline loans. The additional variable amount of interest payable is based on the utilization rate as a percentage of (a) the total amount of funds borrowed under both our senior revolving credit facility and the Plains Offshore senior credit facility and (b) the borrowing base under our senior revolving credit facility. Letter of credit fees under our senior revolving credit facility are based on the utilization rate and range from 1.50% to 2.50%. Commitment fees range from 0.375% to 0.50% of amounts available for borrowing. The effective interest rate on borrowings under our senior revolving credit facility was 2.08% at December 31, 2011.

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.

Plains Offshore Senior Credit Facility. The aggregate commitments of the lenders under the Plains Offshore senior credit facility are $300 million. The Plains Offshore senior credit facility contains a $50 million limit on letters of credit and matures on November 18, 2016. At December 31, 2011, Plains Offshore had no letters of credit outstanding under its senior credit facility.

Amounts borrowed under the Plains Offshore senior credit facility bear an interest rate, at Plains Offshore's election, equal to either: (i) the Eurodollar rate, which is based on LIBOR, plus an additional variable amount ranging from 1.50% to 2.50%; (ii) a variable amount ranging from 0.50% to 1.50% 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%. The additional variable amount of interest payable is based on the utilization rate as a percentage of (a) the total amount of funds borrowed under both our senior revolving credit facility and the Plains Offshore senior credit facility and (b) the borrowing base under our senior revolving credit facility. Letter of credit fees under the Plains Offshore senior credit facility are based on the utilization rate and range from 1.50% to 2.50%. Commitment fees range from 0.375% to 0.50% of amounts available for borrowing.

The borrowings under the Plains Offshore senior credit facility are guaranteed on a senior basis by PXP and certain of our subsidiaries, and are secured on a *pari passu* basis by liens on the same collateral that secures PXP's senior revolving credit facility. The Plains Offshore senior credit facility contains certain affirmative and negative covenants, including limiting Plains Offshore's ability, among other things, to create liens, incur other indebtedness, make dividends (excluding dividends on preferred stock) or other distributions, make investments, change the nature of Plains Offshore's business and merge or consolidate, sell assets, enter into certain types of swap agreements and enter into certain transaction with affiliates, as well as other customary events of default, including a cross-default to PXP's senior revolving credit facility. If an event of default (as defined in our senior revolving credit facility) has occurred and is continuing under our senior revolving credit facility that has not been cured or waived by the lenders thereunder then the Plains Offshore lenders could accelerate and demand repayment of the Plains Offshore senior credit facility.

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, 2012, 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 14 days and all amounts outstanding are due and payable no later than June 1, 2012. 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, 2011. The daily average outstanding balance for the quarter and year ended December 31, 2011 was $43.0 million and $52.6 million, respectively. The weighted average interest rate on borrowings under our short-term credit facility was 1.5% for the years ended December 31, 2011 and 2010.

6¾% Senior Notes. In November 2011, we issued $1 billion of 6¾% Senior Notes due 2022, or the 6¾% Senior Notes, at par. We received approximately $984 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 6¾% Senior Notes on or after February 1, 2017 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to February 1, 2015 we may, at our option, redeem up to 35% of the 6¾% Senior Notes with the proceeds of certain equity offerings.

6⅝% Senior Notes. In March 2011, we issued $600 million of 6⅝% Senior Notes due 2021, or the 6⅝% Senior Notes, at par. We received approximately $590 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 6⅝% Senior Notes on or after May 1, 2016 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to May 1, 2014 we may, at our option, redeem up to 35% of the 6⅝% Senior Notes with the proceeds of certain equity offerings.

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. In December 2011, we made payments totaling $429.5 million to retire $380.1 million of the $565 million outstanding principal amount of our 10% Senior Notes.

7⅝% Senior Notes due 2018. In May 2008, we issued $400 million of 7⅝% Senior Notes due 2018, at par. 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.

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. In December 2011, we made payments totaling $542.2 million to retire $520.7 million of the $600 million outstanding principal amount of our 7¾% Senior Notes.

7% Senior Notes. In March 2007, we issued $500 million principal amount of 7% Senior Notes due 2017, or the 7% Senior Notes, at par. We may redeem all or part of the 7% Senior Notes on or after March 15, 2012 at specified redemption prices and prior to such date at a "make-whole" redemption price. In December 2011, we made payments totaling $442.1 million to retire $423.1 million of the $500 million outstanding principal amount of our 7% Senior Notes.

The 7¾% Senior Notes, 10% Senior Notes, 7% Senior Notes, 7⅝% Senior Notes due 2018, 8⅝% Senior Notes, 7⅝% Senior Notes due 2020, 6⅝% Senior Notes and 6¾% Senior Notes (together, the Senior Notes) are our general unsecured senior obligations. The Senior Notes are jointly and severally guaranteed by certain of our existing domestic subsidiaries. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the assets of that subsidiary guarantor; (ii) in connection with any sale or other disposition of all the capital stock of a subsidiary guarantor; (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of such subsidiary guarantor provided no default or event of default has occurred or is continuing; or (vi) at such time as such subsidiary guarantor does not have outstanding any guarantee of any of our or any of our subsidiary guarantor's indebtedness (other than the notes) in excess of $10.0 million in aggregate principal amount. 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 and the Plains Offshore senior 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.

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 2011, we recognized $121.0 million of debt extinguishment costs, including $30.9 million of unamortized debt issue costs and original issue discount, in connection with the retirement of a portion of our 7¾% Senior Notes, 10% Senior Notes and 7% Senior Notes. During 2010 and 2009, we recognized $1.2 million and $12.1 million, respectively, of debt extinguishment costs in connection with reductions in our borrowing base and commitments under our senior revolving credit facility.

Subsequent Event

In February 2012, our borrowing base was increased from $1.8 billion to $2.3 billion until the next scheduled redetermination date on or before May 1, 2013. The commitments remained unchanged at $1.4 billion.

Note 6 — 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 and Plains Offshore's senior credit facility is variable, while our senior notes are at fixed rates.

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 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. Cash settlements with respect to derivatives that contain a significant financing element are reflected as financing activities in the statement of cash flows.

For put options, we typically 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, is required. If we have less production than the volumes specified under the collar transaction when the floating price exceeds the ceiling price, we must make payments against which there are no offsetting revenues from production.

Under a swap contract, the counterparty is required to make a payment to us if the index price for any settlement period is less than the fixed price, and we are required to make a payment to the counterparty if the index price for any settlement period is greater than the fixed price. The amount we receive or pay is the difference between the index price and the fixed price multiplied by the contract volumes. If we have less production than the volumes specified under the swap transaction when the index price exceeds the fixed price, we must make payments against which there are no offsetting revenues from production.

In December 2011, we entered into natural gas swap contracts at a weighted average price of $4.27 per MMBtu on 110,000 MMBtu per day for 2013.

In September 2011, and in response to our higher priced marketing contracts, we realigned our existing 2012 WTI crude oil put option spread contracts that had an $80 per barrel floor price with a $60 per barrel limit on 40,000 BOPD by acquiring 2012 Brent crude oil three-way collars that have a $100 per barrel floor price with an $80 per barrel limit and a weighted average ceiling price of $120 per barrel. The realignment eliminated $89.1 million of deferred premiums and interest associated with the previous 2012 WTI crude oil put option spread contracts. We also paid net upfront premiums of approximately $2.6 million to enter into the 2012 Brent three-way collars. Additionally, we converted 40,000 of the 160,000 MMBtu per day 2012 natural gas put option spread contracts that had a $4.30 per MMBtu floor price with a $3.00 per MMBtu limit to natural gas three-way collars that have a $4.30 per MMBtu floor price with a $3.00 per MMBtu limit and a weighted average ceiling price of $4.86 per MMBtu and reduced 2012 deferred premiums and interest by approximately $4.1 million. We also acquired 2013 Brent crude oil put option spread contracts that have a $90 per barrel floor price with a $70 per barrel limit and weighted average deferred premium and interest of $6.237 per barrel on 22,000 BOPD.

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

As of December 31, 2011, 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					
2012					
Jan - Dec	Three-way collars (2)	40,000 Bbls	$100.00 Floor with an $80.00 Limit $120.00 Ceiling	-	Brent
2013					
Jan - Dec	Put options (3)	22,000 Bbls	$90.00 Floor with a $70.00 Limit	$6.237 per Bbl	Brent
Sales of Natural Gas Production					
2012					
Jan - Dec	Put options (4)	120,000 MMBtu	$4.30 Floor with a $3.00 Limit	$0.298 per MMBtu	Henry Hub
Jan - Dec	Three-way collars (5)	40,000 MMBtu	$4.30 Floor with a $3.00 Limit $4.86 Ceiling	-	Henry Hub
2013					
Jan - Dec	Swap contracts (6)	110,000 MMBtu	$4.27	-	Henry Hub

(1) The average strike prices do not reflect any premiums to purchase the put options.

(2) If the index price is less than the $100 per barrel floor, we receive the difference between the $100 per barrel floor and the index price up to a maximum of $20 per barrel. We pay the difference between the index price and $120 per barrel if the index price is greater than the $120 per barrel ceiling. If the index price is at or above $100 per barrel but at or below $120 per barrel, no cash settlement is required.

(3) If the index price is less than the $90 per barrel floor, we receive the difference between the $90 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 $90 per barrel, we pay only the option premium.

(4) 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.

(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. We pay the difference between the index price and $4.86 per MMBtu if the index price is greater than the $4.86 per MMBtu ceiling. If the index price is at or above $4.30 per MMBtu but at or below $4.86 per MMBtu, no cash settlement is required.

(6) If the index price is less than the $4.27 per MMBtu fixed price, we receive the difference between the $4.27 per MMBtu fixed price and the index price. We pay the difference between the index price and the fixed price if the index price is greater than the fixed price.

Balance Sheet

At December 31, 2011 and 2010, 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**	**2011**	**2010**
Crude oil puts	Commodity derivative contracts - current assets	$ -	$ 23,910
Crude oil collars	Commodity derivative contracts - current assets (liabilities)	10,623	(317)
Natural gas puts	Commodity derivative contracts - current assets	41,335	-
Natural gas collars	Commodity derivative contracts - current assets (liabilities)	13,163	(10,469)
Crude oil puts	Commodity derivative contracts - non-current assets	48,306	64,266
Natural gas puts	Commodity derivative contracts - non-current assets	-	15,254
Natural gas swaps	Commodity derivative contracts - non-current assets	12,951	-
Total derivative instruments		$ 126,378	$ 92,644

The following table provides supplemental information to reconcile the fair value of our derivative contracts to our balance sheet at December 31, 2011 and 2010, considering the deferred premiums, accrued interest and related settlement payable/receivable amounts which are not included in the fair value amounts disclosed in the table above (in thousands):

	Year Ended December 31,	
	2011	**2010**
Net fair value asset	$ 126,378	$ 92,644
Deferred premium and accrued interest on derivative contracts	(62,430)	(164,155)
Settlement payable	(5,106)	(6,200)
Settlement receivable	216	-
Net commodity derivative asset (liability)	$ 59,058	$ (77,711)
Commodity derivative contracts - current asset	$ 50,964	$ -
Commodity derivative contracts - non-current asset	12,678	-
Commodity derivative contracts - current liability	(3,761)	(52,971)
Commodity derivative contracts - non-current liability	(823)	(24,740)
	$ 59,058	$ (77,711)

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, 2011, 2010 and 2009, pre-tax amounts recognized in our income statements for derivative transactions were as follows (in thousands):

	Year Ended December 31,		
	2011	**2010**	**2009**
Gain (loss) on mark-to-market derivative contracts	$ 81,981	$ (60,695)	$ (7,017)

Cash Payments and Receipts

During the years ended December 31, 2011, 2010 and 2009 cash (payments) receipts for derivatives were as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Oil derivatives			
Settlements	$ (60,392)	$ (67,917)	$ 141,297
Unwind of crude oil puts, swaps and collars	(2,935)	-	1,074,361
Natural gas derivatives	7,915	37,996	308,146
	$ (55,412)	$ (29,921)	$ 1,523,804

Credit Risk

We generally do not require collateral or other security to support derivative instruments subject to credit risk. However, the agreements with each of the counterparties to our derivative instruments contain netting provisions within the agreements. If a default occurs under the agreements, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contracts with the amount due from the defaulting party under the derivative contracts. As a result of the netting provisions under the agreements, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that we would have incurred if all the counterparties to our derivative contracts failed to perform according to the terms of the derivative contracts at December 31, 2011 was $63.6 million.

Contingent Features

As of December 31, 2011, the counterparties to our commodity derivative contracts consisted of eight 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, 2011, we were in a net liability position with one of the counterparties to our derivative instruments, totaling $3.5 million.

Subsequent Events

During the period from January 1, 2012 through February 22, 2012, we converted 5,000 of the 22,000 BOPD of Brent crude oil put option contracts in 2013 to three-way collars. These modified three-way collars have a floor price of $90 per barrel with a limit of $70 per barrel and a weighted average ceiling price of $126.08 and eliminates approximately $11 million of deferred premiums. Additionally, we entered into the following Brent oil derivatives for 2013 and 2014:

- Brent crude oil put option spread contracts on 13,000 BPOD for 2013 with a floor price of $100 per barrel and a limit of $80 per barrel.

- Brent three-way collars on 25,000 BOPD for 2013 that have a floor price of $100 per barrel with a limit of $80 per barrel and a weighted average ceiling price of $124.29 per barrel.
- Brent crude oil put option spread contracts on 20,000 BOPD for 2014 with a floor price of $90 per barrel and a limit of $70 per barrel.

In February 2012, we entered into natural gas swap contracts, at an average price of $4.16 per MMBtu, on 70,000 MMBtu per day for 2014.

Note 7 — Investment

At December 31, 2011 and 2010, we owned 51.0 million shares of McMoRan Exploration Co. common stock, approximately 31.6% and 32.4%, respectively, of its 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. In December 2010, we acquired the McMoRan common stock and other consideration in exchange for all of our interests in our U.S. 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 filed 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 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). The one year restriction ended on December 30, 2011, and we may now sell shares of McMoRan common stock pursuant to underwritten offerings, in periodic sales under the shelf registration statement filed by McMoRan (subject to certain volume limitations), pursuant to the exercise of piggyback registration rights or as otherwise permitted by applicable law. Our investment in McMoRan was reclassified from long-term to current assets as the one year restriction to sell the shares ended on December 30, 2011.

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 recognized as a gain or loss on investment measured at fair value 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, 2011 and 2010, the McMoRan shares were valued at approximately $611.7 million and $664.3 million, respectively, based on McMoRan's closing stock prices of $14.55 and $17.14 on December 31, 2011 and 2010, respectively, discounted to reflect certain limitations on the marketability of the McMoRan shares. During the years ended December 31, 2011 and 2010, we recorded unrealized losses of $52.7 million and $1.6 million, respectively, on our investment.

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 and results of operations (in thousands):

	December 31, 2011	December 31, 2010
Financial Position (1)		
Current assets	$ 217,063	$ 339,176
Noncurrent assets	711,729	600,217
Current liabilities	133,162	135,511
Noncurrent liabilities	251,173	245,198
Net assets	$ 544,457	$ 558,684

	Year Ended December 31, 2011
Results of Operations (1)	
Revenues	$ 175,511
Operating income	432
Loss from continuing operations	(2,087)
Net loss applicable to common stock	(18,571)

(1) Amounts represent our 31.6% and 32.4% equity ownership in McMoRan as of December 31, 2011 and 2010, respectively. We acquired our McMoRan investment 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 8 — 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, 2011 and 2010 (in thousands):

		Fair Value Measurements at Reporting Date Using		
	Fair Value	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
2011				
Commodity derivative contracts (1)				
Crude oil puts	$ 48,306	$ -	$ -	$ 48,306
Crude oil collars	10,623	-	(669)	11,292
Natural gas puts	41,335	-	-	41,335
Natural gas collars	13,163	-	-	13,163
Natural gas swaps	12,951	-	12,951	-
Investment (2)	611,671	-	-	611,671
	$ 738,049	$ -	$ 12,282	$ 725,767
2010				
Commodity derivative contracts (1)				
Crude oil puts	$ 88,176	$ -	$ 88,176	$ -
Crude oil collars	(317)	-	(317)	-
Natural gas puts	15,254	-	-	15,254
Natural gas collars	(10,469)	-	-	(10,469)
Investment (2)	664,346	-	-	664,346
	$ 756,990	$ -	$ 87,859	$ 669,131

(1) Option premium and accrued interest of $62.4 million and $164.2 million at December 31, 2011 and 2010, respectively, settlement payable of $5.1 million and $6.2 million at December 31, 2011 and 2010, respectively, and settlement receivable of $0.2 million at December 31, 2011 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 put and collar derivative instruments are estimated using an option-pricing model, which uses various inputs including NYMEX and ICE price quotations, volatilities, interest rates and contract terms. The fair value of our swap derivative instruments are estimated using a pricing model which has various inputs including NYMEX price quotations, 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 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 and/or interpolate data between data points for thinly traded instruments. As of December 31, 2011, our 2013 natural gas swaps and certain of our 2012 crude oil collars are classified as Level 2, certain of our 2012 crude oil collars are classified as Level 3 and all of our 2012 natural gas and 2013 crude oil contracts are classified as Level 3 instruments.

We determine the fair value of our investment by discounting 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, implied volatility of the instrument, number of shares 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, 2011, 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, 2011 and 2010 (in thousands):

	Year Ended December 31,			
	2011		2010	
	Commodity Derivatives (1)	Investment	Commodity Derivatives (1)	Investment
Fair value at beginning of period	$ 4,785	$ 664,346	$ 14,312	$ -
Transfers (2)	6,962	-	-	-
Purchases	47,948	-	16,894	665,897
Realized and unrealized gains and losses included in earnings (3)	56,775	(52,675)	12,613	(1,551)
Settlements	(2,374)	-	(39,034)	-
Fair value at end of period	$ 114,096	$ 611,671	$ 4,785	$ 664,346
Change in unrealized gains and losses relating to assets and liabilities held as of the end of the period (3)	$ 50,894	$ (52,675)	$ (12,108)	$ (1,551)

(1) Deferred option premiums and interest are not included in the fair value of derivatives.
(2) During the third quarter of 2011, the inputs used to value certain of our 2011 natural gas collars were directly or indirectly observable and those contracts were transferred to Level 2.
(3) Realized and unrealized gains and losses included in earnings for the period are reported as gain (loss) on mark-to-market derivative contracts and loss on investment measured at fair value 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 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, 2011 and 2010 (in thousands):

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Current Liability				
Deferred premium and accrued interest on derivative contracts	$ 13,029	$ 13,029	$ 59,895	$ 59,895
Non-Current Liability				
Deferred premium and accrued interest on derivative contracts	49,401	49,401	104,260	104,260
Long-Term Debt				
Senior revolving credit facility	735,000	735,000	620,000	620,000
Plains Offshore senior credit facility	-	-	-	-
7¾% Senior Notes	79,281	81,858	600,000	625,500
10% Senior Notes	175,385	194,239	530,812	631,388
7% Senior Notes	76,901	79,593	500,000	513,750
7⅝% Senior Notes	400,000	424,000	400,000	421,000
8⅝% Senior Notes	394,385	433,331	393,905	438,000
7⅝% Senior Notes	300,000	324,750	300,000	316,125
6⅝% Senior Notes	600,000	630,000	-	-
6¾% Senior Notes	1,000,000	1,047,500	-	-

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 9 — Asset Retirement Obligation

The following table reflects the changes in our asset retirement obligation during the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Asset retirement obligation – beginning of period	$ 239,432	$ 221,367	$ 169,809
Liabilities incurred in acquisitions	6	246	-
Property dispositions and other	(19,406)	(7,883)	-
Settlements	(13,998)	(3,718)	(3,699)
Change in estimate	7,463	6,179	39,518
Accretion expense	17,177	17,702	14,332
Asset retirement additions	7,707	5,539	1,407
Asset retirement obligation – end of period (1)	$ 238,381	$ 239,432	$ 221,367

(1) $7.7 million and $13.9 million are included in other current liabilities at December 31, 2011 and 2010, 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 10 — 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, 2011, 2010 and 2009 was (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Stock-based compensation included in:			
General and administrative expense	$ 42,268	$ 46,953	$ 56,098
Lease operating expenses	6,925	3,922	4,392
Oil and natural gas properties	13,695	14,662	15,930
Total stock-based compensation	$ 62,888	$ 65,537	$ 76,420

Stock-based compensation charged to earnings for the years ended December 31, 2011, 2010 and 2009 was (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Charged to earnings	$ 49,193	$ 50,875	$ 60,490
Tax benefit	(18,438)	(19,068)	(22,714)
	$ 30,755	$ 31,807	$ 37,776

At December 31, 2011, there was $169.5 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 3.9 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, 2011 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, 2011	3,156	$ 37.29		
Granted	955	36.91		
Exercised	(250)	26.43		
Forfeited or expired	(291)	36.91		
Outstanding at December 31, 2011	3,570	37.98	$ 13,815	2.3
Exercisable at December 31, 2011	1,612	46.25	$ 2,410	1.0

The total intrinsic value of SARs exercised during the years ended December 31, 2011, 2010 and 2009 was $2.9 million, $0.6 million and $0.4 million, respectively. The weighted average grant date fair value per share for SARs granted in 2011, 2010 and 2009 was $13.65, $11.08 and $6.44, respectively.

We estimate the fair value of SARs granted using the Black-Scholes valuation model. The following assumptions are as of December 31, 2011, 2010 and 2009:

	2011	2010	2009
Expected life (in years)	1 - 4	1 - 4	1 - 4
Volatility	47.4% - 52.2%	45.3% - 56.3%	41.7% - 78.1%
Risk-free interest rate	0.1% - 0.6%	0.3% - 1.5%	0.5% - 2.2%
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, 2011 and the changes during the year then ended:

	Equity Instruments (thousands)	Weighted Average Grant Date Fair Value Price	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractual Life (years)
Nonvested at January 1, 2011	6,306	$ 40.50		
Granted	1,630	37.18		
Vested	(1,279)	35.44		
Vested and deferred	(323)	39.95		
Forfeited	(50)	33.54		
Nonvested at December 31, 2011	6,284	40.97	$ 230,714	4.2

The total intrinsic value of restricted stock and RSUs vested in 2011, 2010 and 2009 was $54.0 million, $41.0 million and $24.6 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, 2010 and 2009 was $31.23 per share and $22.27 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 1.9 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 2012 through 2015 but payment of vested RSUs will be generally deferred until September 30, 2015, subject to certain exceptions. At December 31, 2011, 1.2 million nonvested shares had been granted and 0.7 million nonvested shares will be granted in 2012 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, 2011, there were 6,176 stock options outstanding with an average exercise price of $7.92 per share and an average remaining life of 0.7 years. The intrinsic value of options exercised in the years ended December 31, 2011, 2010 and 2009 was $22,000, $0.4 million and $0.1 million, respectively, and we received $8,000, $0.2 million and $0.1 million, respectively, upon the exercise of such options.

Other

We have a 401(k) defined contribution plan whereby we have matched 100% of an employee's contribution (subject to certain limitations in the plan). In 2011, 2010 and 2009 we made cash contributions totaling $10.3 million, $9.2 million and $9.3 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 2011, 2010 and 2009, approximately 318,000, 348,000 and 163,000 common shares, respectively, vested and were deferred resulting in a total of approximately 1,046,000 deferred common shares at December 31, 2011. These common shares will be issued upon the earliest of the deferral date, their retirement or death.

Note 11 — Income Taxes

For the years ended December 31, 2011, 2010 and 2009 our income (loss) before income taxes consisted of (in thousands):

	Year Ended December 31,		
	2011	2010	2009
U.S.	$ 341,378	$ 263,917	$ 218,422
Non U.S.	(437)	(59,907)	(1,242)
	$ 340,941	$ 204,010	$ 217,180

For the years ended December 31, 2011, 2010 and 2009 our income tax (benefit) expense consisted of (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Current			
U.S. Federal	$ (25,673)	$ (89,680)	$ 40,548
State	(279)	(3,410)	4,543
	$ (25,952)	$ (93,090)	$ 45,091
Deferred			
U.S. Federal	$ 150,266	$ 180,384	$ 36,530
State	9,948	13,451	(746)
	$ 160,214	$ 193,835	$ 35,784
	$ 134,262	$ 100,745	$ 80,875

Our deferred income tax assets and liabilities at December 31, 2011 and 2010 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, 2011	December 31, 2010
Deferred tax assets		
Net operating loss	$ 372,300	$ 70,746
Tax credits	52,497	53,265
Stock-based compensation, commodity derivative contracts and other	56,431	82,005
Oil and gas acquisition, exploration and development operations	-	223,909
	481,228	429,925
Deferred tax liabilities		
Commodity derivative contracts	(24,091)	-
Net oil and gas acquisition, exploration and development operations and other	(1,898,311)	(1,710,889)
Net deferred tax liability	$ (1,441,174)	$ (1,280,964)
Current asset	$ 20,723	$ 74,086
Long-term liability	(1,461,897)	(1,355,050)
Net deferred tax liability	$ (1,441,174)	$ (1,280,964)

Tax carryforwards at December 31, 2011, which are available for future utilization on income tax returns, are as follows (in thousands):

FEDERAL - PXP and Consolidated Subsidiaries	**Amount**	**Expiration**
Alternative minimum tax (AMT) credit	$ 2,242	-
Enhanced oil recovery credit	35,424	2025
Net operating loss – regular tax	753,469	2027 - 2031
Net operating loss – AMT tax	385,318	2031
FEDERAL – Plains Offshore		
Net operating loss – regular tax	$ 3,549	2031
Net operating loss – AMT tax	908	2031
STATE – PXP and Combined Subsidiaries		
AMT credit	$ 521	-
Enhanced oil recovery credit	22,296	2016 - 2020
Net operating loss – regular tax	2,014,626	2021 - 2031
Net operating loss – AMT tax	318,813	2031

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

	Year Ended December 31,		
	2011	2010	2009
U.S. federal income tax provision at statutory rate	$ 119,329	$ 71,404	$ 76,013
State income taxes, net of federal expense	9,669	10,041	1,025
Non-deductible expenses	10,389	14,644	15,839
Uncertain tax positions	(6,277)	(1,169)	(18,154)
Non-cash compensation	-	2,506	4,776
Other	1,152	3,319	1,376
Income tax expense on income before income taxes	$ 134,262	$100,745	$ 80,875

Tax Relationship with Plains Offshore. As of December 31, 2011, Plains Offshore was not consolidated with us for federal income tax purposes. Plains Offshore files a separate federal tax return and has its own federal tax loss carryforwards and other tax attributes. Plains Offshore may or may not be combined with us and our other subsidiaries for state tax filing purposes dependent upon the applicable state tax rules. We and Plains Offshore have entered into a Tax Matters Agreement, or TMA, which governs Plains Offshore's and our respective rights, responsibilities, and obligations with respect to the filing of tax returns, payment of taxes, conduct of tax audits and certain other tax matters.

Under the TMA, Plains Offshore is obligated to reimburse us for its share of taxes that are paid by us and can receive payment from us for any Plains Offshore tax attributes utilized by us related to our tax returns filed on a consolidated, combined or unitary basis including Plains Offshore but only to the extent and at such time as Plains Offshore would have paid the tax or utilized such attributes on a separate return basis. To the extent Plains Offshore files tax returns which are not consolidated, combined or unitary with us, Plains Offshore pays its tax liabilities directly to the applicable taxing authority.

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 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.

Valuation Allowance. In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the related deferred tax benefits will not be realized. We consider the scheduled reversal of deferred tax liabilities, projected future income and tax planning strategies in making the assessment of whether it is more likely than not that some portion or all of our deferred tax assets will not be realized. Based on this assessment as of December 31, 2011, no valuation allowances were necessary.

Other Tax Matters. We did not record a tax benefit related to non-cash employee compensation for 2011 since we generated a net operating loss for federal tax purposes in 2011 which will be carried forward to future periods. As the Company utilizes this net operating loss in future periods, a tax benefit of $0.2 million will be credited to additional paid-in capital as a result of the non-cash employee compensation that vested in 2011. 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):

	2011	2010	2009
Balance at beginning of period	$ 13,896	$ 16,473	$ 47,163
Additions based on tax positions related to the current year	-	-	-
Adjustments for audit settlements in the current year	-	(1,901)	(33,775)
Additions for tax positions in prior years	-	-	3,085
Reductions for tax positions of prior years	(833)	-	-
Adjustments due to any expiration of a statute of limitations	(5,752)	(676)	-
Balance at end of period	$ 7,311	$ 13,896	$ 16,473

During 2011, our balance of net unrecognized tax benefits decreased by $6.1 million primarily as a result of the expiration of the statute of limitations for various tax years. 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. During 2009, we received revenue agent reports from the IRS relating to tax years under audit. 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.

We estimate our balance of net unrecognized tax benefits will be reduced by $5.0 million over the next twelve months as the statute of limitations expires for various tax years. Included in the balance at December 31, 2011 is approximately $6.9 million that would affect our effective tax rate if recognized. The difference between this amount and the $7.3 million ending balance of gross unrecognized tax benefits represents the federal benefit of state tax positions.

We had approximately $1.8 million and $3.1 million of accrued interest on unrecognized tax benefits in our balance sheets as of December 31, 2011 and 2010, respectively. We did not have any accrued liabilities for penalties related to unrecognized tax benefits for the years ended December 31, 2011 and 2010.

We file income tax returns in the U.S. federal and various state and foreign jurisdictions. As of December 31, 2011, 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. In December 2011, the state of New Mexico commenced an audit of Pogo's 2007 New Mexico income tax return. Also in 2011, the state of Texas informed us that an audit of our 2008 Texas Franchise Tax return will commence in 2012. In all states except California and New Mexico, we are no longer subject to state income tax examinations by the relevant tax authorities for years prior to 2008. For California and New Mexico, we are no longer subject to state income tax examinations for years prior to 2007 except for certain California tax loss and credit carryforwards generated before 2007 but utilized after 2006.

Note 12 — 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):

2012	$ 15,016
2013	14,232
2014	13,941
2015	13,304
2016	10,734
Thereafter	34,911
	$ 102,138

Total expenses related to such leases were $12.2 million, $12.3 million and $13.0 million in 2011, 2010 and 2009, respectively.

Contractual Obligations. As is common within the industry, we have entered into various commitments and operating agreements associated with, among other things, oil and gas exploration, development and production activities, gathering and transportation, drilling rig and oilfield and other services. Aggregate future obligations under these agreements, described below, total $770.4 million, of which approximately $226.6 million is expected to be paid in 2012, $176.9 million in 2013, $112.2 million in 2014, $39.8 million in 2015, $39.4 million in 2016 and $175.5 million thereafter.

Through our ownership in Lucius, located in the deepwater U.S. Gulf of Mexico, we joined the Lucius and Hadrian working interest partners and executed a unit participation and unit operating agreement effective June 1, 2011. As part of the agreements, we have agreed to share in our portion of certain long lead equipment orders and detailed engineering work and have a commitment of approximately $314.3 million remaining under the development plan.

Plains Offshore and its partners have entered into various agreements with third parties for long-term oil and gas gathering and transportation services at the Lucius oil field. Beginning in 2014, Plains Offshore will pay guaranteed fixed minimum monthly fees plus additional variable gathering fees based upon actual throughput. The commitments of Plains Offshore under the oil gathering agreements are guaranteed by PXP.

We have commitments for hydraulic fracturing services, coil tubing services and drilling rig contracts with terms from one year up to three years primarily to perform our Eagle Ford Shale drilling program.

At our Arroyo Grande field in San Luis Obispo County, California, we have committed for the design and construction of a produced water reclamation facility. Additionally, we have signed a ten-year operations agreement for the facility which will commence upon commercial operations.

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 2012 cash expenditures related to plugging, abandonment and remediation will be approximately $7.7 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, $82.6 million ($145.2 million undiscounted), is included in our asset retirement obligation as reflected on 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 $86.1 million). To secure its abandonment obligations, the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2011, the escrow account had a balance of $17.7 million. The fair value of our guarantee at December 31, 2011, $0.7 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. 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 2011, 2010 and 2009, sales to ConocoPhillips accounted for 41%, 57% and 44%, respectively, of our total revenues. During 2011, sales to Tesoro Corporation and Valero Energy Corporation accounted for 13% and 11%, respectively, of our total revenues. The contract with Tesoro Corporation expired in November 2011. We did not renew this contract, and upon expiration we entered into a contract with ConocoPhillips for these volumes. During 2009, sales to Plains Marketing, L.P., or PMLP, accounted for 22% 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 2011, 2010 and 2009, 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 do not currently require letters of credit or other collateral from the above stated purchasers to support trade receivables. Accordingly, a material adverse change in purchaser'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 13 — Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2011	2010	2009
Cash payments for interest (net of capitalized interest)	$ 164,474	$ 98,262	$ 45,496
Cash (receipts) payments for income taxes	$ (62,414)	$ (58,920)	$ 151,682

At December 31, 2011 and 2010, accrued capital expenditures included in accounts payable in the balance sheet were $196.0 million and $150.1 million, respectively.

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

	Year Ended December 31,		
	2011	2010	2009
Shares (1)	876	728	765
Amount (1)	$ 31,052	$ 21,232	$ 15,498

(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 in 2010 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; and
- non-cash additions to oil and gas properties of $12.9 million, $21.8 million and $55.3 million in 2011, 2010 and 2009, respectively, related to our asset retirement obligation.

Certain of our commodity derivative contracts include deferred premiums to be paid to the counterparty based on the settlement terms specified in the contract. During 2011, 2010 and 2009, we entered into derivative contracts with deferred premiums of $49.2 million, $162.9 million and $74.1 million, respectively. In connection with our September 2011 derivative transactions, we eliminated $93.2 million of deferred premiums and interest associated with contracts entered into in 2010.

Note 14 — Equity

Earnings Per Common Share

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

	Year Ended December 31,		
	2011	2010	2009
Common shares outstanding – basic	141,227	140,438	124,405
Unvested restricted stock, restricted stock units and stock options	1,772	1,459	883
Common shares outstanding – diluted	142,999	141,897	125,288

Included in computing our basic earnings per common 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, 2011, 2010 and 2009, 1.4 million, 1.8 million and 2.4 million, respectively, restricted stock units were excluded in computing diluted earnings per common 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.

In computing our earnings per share for 2011, we decreased our reported net income by the $1.4 million in preferred stock dividends attributable to the noncontrolling interest associated with our consolidated subsidiary Plains Offshore. We owned 100% of the common shares of Plains Offshore during 2011, and because Plains Offshore had a net loss for 2011, we did not allocate any undistributed earnings to the noncontrolling interest preferred stock. In the event that Plains Offshore has net income in future periods, we will be required to allocate distributed and undistributed earnings between the common and preferred shares of Plains Offshore.

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.

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.

Authorized Shares

The number of our authorized common shares at December 31, 2011 is 250.0 million, with a par value of $0.01.

The number of our authorized preferred shares at December 31, 2011 is 5.0 million, with a par value of $0.01. No PXP preferred shares were issued as of December 31, 2011.

Stock Repurchase Program

During the year ended December 31, 2011, we repurchased 10.4 million common shares at an average cost of $34.73 per share totaling $361.7 million.

In January 2012, we completed the purchase of an additional 2.4 million common shares at an average cost of $37.02 per share totaling $88.5 million. Subsequent to those purchases, our Board of Directors reset the authorization to $1.0 billion of PXP common stock, all of which is available for repurchase, and extended the program until January 2016.

Note 15 — Other Operating (Income) Expense and Other Income

Other operating income for 2011 and 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 consists of the following (in thousands):

	Year Ended December 31,		
	2011	**2010**	**2009**
Royalty receipts and related interest [(1)]	$ -	$ 8,121	$ 23,501
Preacquisition adjustments [(1)]	271	4,998	3,203
Other	3,085	2,823	1,264
	$ 3,356	$ 15,942	$ 27,968

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

Note 16 — Consolidating Financial Statements

We are the issuer of 7¾% Senior Notes, 10% Senior Notes, 7% Senior Notes, 7⅝% Senior Notes due 2018, 8⅝% Senior Notes, 7⅝% Senior Notes due 2020, 6⅝% Senior Notes and 6¾% Senior Notes as of December 31, 2011, which are jointly and severally guaranteed by certain of our existing domestic subsidiaries (referred to as "Guarantor Subsidiaries"). In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the assets of that subsidiary guarantor; (ii) in connection with any sale or other disposition of all the capital stock of a subsidiary guarantor; (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of such subsidiary guarantor provided no default or event of default has occurred or is continuing; or (vi) at such time as such subsidiary guarantor does not have outstanding any guarantee of any of our or any of our subsidiary guarantor's indebtedness (other than the notes) in excess of $10.0 million in aggregate principal amount. Certain of our subsidiaries do not guarantee the Senior Notes (referred to as "Non-Guarantor Subsidiaries").

PXP Operations LLC. During the first half of 2011, the reverse like-kind exchange arrangements pursuant to IRC Section 1031 were concluded prior to the completion of a like-kind exchange involving any disposition of PXP properties. As a result, the related Eagle Ford Shale properties were transferred from PXP Operations LLC, which was reported as a Non-Guarantor Subsidiary, to PXP, which is reported as Issuer, and the outstanding notes between PXP Operations LLC and PXP were settled. We have retrospectively adjusted the Issuer, Non-Guarantor Subsidiaries and Intercompany Eliminations columns of the condensed consolidating balance sheet at December 31, 2010 and the consolidating statements of income and cash flows for the year ended December 31, 2010 to reflect the unwind of the reverse like-kind exchange arrangement involving PXP Operations LLC.

Plains Offshore. In October 2011, we entered into a securities purchase agreement with EIG pursuant to which we received $430.2 million of net cash proceeds in exchange for a 20% equity interest in Plains Offshore. Plains Offshore holds all of our oil and natural gas properties and assets located in the United States Gulf of Mexico in water depths of 500 feet or more. As a result, the associated deepwater properties were transferred from PXP, which is reported as Issuer, to Plains Offshore, which is reported as a Non-Guarantor Subsidiary. We have retrospectively adjusted the Issuer, Non-Guarantor Subsidiaries and Intercompany Eliminations columns of the condensed consolidating balance sheet at December 31, 2010 and the consolidating statements of income and cash flows for the years ended December 31, 2010 and 2009 to reflect the transfer of these deepwater assets.

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, 2011
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 3,189	$ 6	$ 415,903	$ -	$ 419,098
Accounts receivable and other current assets	885,860	136,642	444	(667)	1,022,279
	889,049	136,648	416,347	(667)	1,441,377
Property and Equipment, at cost					
Oil and natural gas properties - full cost method	4,301,524	8,841,469	1,282,708	-	14,425,701
Other property and equipment	52,906	42,747	50,306	-	145,959
	4,354,430	8,884,216	1,333,014	-	14,571,660
Less allowance for depreciation, depletion, amortization and impairment	(2,327,063)	(6,392,068)	(1,059,186)	2,931,952	(6,846,365)
	2,027,367	2,492,148	273,828	2,931,952	7,725,295
Investment in and Advances to Affiliates	4,583,550	(1,282,085)	(73,079)	(3,228,386)	-
Other Assets	73,832	548,615	2,353	-	624,800
	$ 7,573,798	$ 1,895,326	$ 619,449	$ (297,101)	$ 9,791,472
LIABILITIES AND EQUITY					
Current Liabilities	$ 443,098	$ 135,681	$ 48,074	$ (667)	$ 626,186
Long-Term Debt	3,760,952	-	-	-	3,760,952
Other Long-Term Liabilities	211,106	35,296	803	-	247,205
Deferred Income Taxes	(105,994)	437,367	31,757	1,098,767	1,461,897
Equity					
Stockholders' equity	3,264,636	1,286,982	108,219	(1,395,201)	3,264,636
Noncontrolling interest					
Preferred stock of subsidiary	-	-	430,596	-	430,596
	3,264,636	1,286,982	538,815	(1,395,201)	3,695,232
	$ 7,573,798	$ 1,895,326	$ 619,449	$ (297,101)	$ 9,791,472

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	261,005	133,761	1,687	-	396,453
	267,025	133,769	2,093	-	402,887
Property and Equipment, at cost					
Oil and natural gas properties - full cost method	3,403,728	8,721,483	1,154,399	-	13,279,610
Other property and equipment	49,110	41,736	46,304	-	137,150
	3,452,838	8,763,219	1,200,703	-	13,416,760
Less allowance for depreciation, depletion, amortization and impairment	(2,139,800)	(5,769,846)	(563,685)	2,277,323	(6,196,008)
	1,313,038	2,993,373	637,018	2,277,323	7,220,752
Investment in and Advances to Affiliates	5,024,555	(1,562,441)	(66,116)	(3,395,998)	-
Other Assets	726,277	545,021	-	-	1,271,298
	$ 7,330,895	$ 2,109,722	$ 572,995	$ (1,118,675)	$ 8,894,937
LIABILITIES AND EQUITY					
Current Liabilities	$ 361,282	$ 147,246	$ 25,161	$ -	$ 533,689
Long-Term Debt	3,344,717	-	-	-	3,344,717
Other Long-Term Liabilities	214,491	61,761	2,264	-	278,516
Deferred Income Taxes	27,440	323,829	178,906	824,875	1,355,050
Equity	3,382,965	1,576,886	366,664	(1,943,550)	3,382,965
	$ 7,330,895	$ 2,109,722	$ 572,995	$ (1,118,675)	$ 8,894,937

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2011
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 1,271,176	$ 256,558	$ 922	$ -	$ 1,528,656
Gas sales	16,910	411,310	-	-	428,220
Other operating revenues	1,309	6,303	-	-	7,612
	1,289,395	674,171	922	-	1,964,488
Costs and Expenses					
Production costs	360,643	198,332	-	-	558,975
General and administrative	81,720	49,866	2,458	-	134,044
Depreciation, depletion, amortization and accretion	214,389	271,747	339	195,180	681,655
Impairment of oil and gas properties	-	354,305	495,504	(849,809)	-
Other operating expense (income)	184	(919)	-	-	(735)
	656,936	873,331	498,301	(654,629)	1,373,939
Income (Loss) from Operations	632,459	(199,160)	(497,379)	654,629	590,549
Other (Expense) Income					
Equity in earnings of subsidiaries	(124,416)	-	-	124,416	-
Interest expense	(1,320)	(156,580)	(3,416)	-	(161,316)
Debt extinguishment costs	(120,954)	-	-	-	(120,954)
Gain on mark-to-market derivative contracts	81,981	-	-	-	81,981
Loss on investment measured at fair value	(52,675)	-	-	-	(52,675)
Other income (expense)	1,521	1,893	(58)	-	3,356
Income (Loss) Before Income Taxes	416,596	(353,847)	(500,853)	779,045	340,941
Income tax (expense) benefit	(211,317)	137,153	172,961	(233,059)	(134,262)
Net Income (Loss)	205,279	(216,694)	(327,892)	545,986	206,679
Net income attributable to noncontrolling interest in the form of preferred stock of subsidiary	-	-	(1,400)	-	(1,400)
Net Income (Loss) Attributable to Common Stockholders	$ 205,279	$ (216,694)	$ (329,292)	$ 545,986	$ 205,279

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	$ 952,714	$ 190,046	$ -	$ -	$ 1,142,760
Gas sales	67,780	331,827	-	-	399,607
Other operating revenues	884	1,344	-	-	2,228
	1,021,378	523,217	-	-	1,544,595
Costs and Expenses					
Production costs	296,285	155,617	-	-	451,902
General and administrative	87,043	48,322	1,072	-	136,437
Depreciation, depletion, amortization and accretion	218,905	161,006	144	171,063	551,118
Impairment of oil and gas properties	-	266,442	63,636	(270,603)	59,475
Legal recovery	-	(8,423)	-	-	(8,423)
Other operating income	(988)	(3,142)	-	-	(4,130)
	601,245	619,822	64,852	(99,540)	1,186,379
Income (Loss) from Operations	420,133	(96,605)	(64,852)	99,540	358,216
Other (Expense) Income					
Equity in earnings of subsidiaries	(119,427)	(68)	-	119,495	-
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	239,714	(187,570)	(67,169)	219,035	204,010
Income tax (expense) benefit	(136,449)	50,995	3,983	(19,274)	(100,745)
Net Income (Loss)	$ 103,265	$ (136,575)	$ (63,186)	$ 199,761	$ 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	102,330	40,960	1,296	-	144,586
Depreciation, depletion, amortization and accretion	212,128	158,059	61	51,332	421,580
Impairment of oil and gas properties	-	1,712,201	241,761	(1,953,962)	-
Legal recovery	(81,790)	(5,482)	-	-	(87,272)
Other operating expense (income)	6,307	(4,736)	565	-	2,136
	529,783	2,034,161	243,683	(1,902,630)	904,997
Income (Loss) from Operations	298,972	(1,675,786)	(243,683)	1,902,630	282,133
Other (Expense) Income					
Equity in earnings of subsidiaries	(18,612)	(1,041)	-	19,653	-
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	250,839	(1,709,359)	(246,583)	1,922,283	217,180
Income tax (expense) benefit	(114,534)	660,149	81,813	(708,303)	(80,875)
Net Income (Loss)	$ 136,305	$(1,049,210)	$ (164,770)	$ 1,213,980	$ 136,305

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2011
(in thousands of dollars)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 205,279	$ (216,694)	$ (327,892)	$ 545,986	$ 206,679
Items not affecting cash flows from operating activities					
Depreciation, depletion, amortization, accretion and impairment	214,389	626,052	495,843	(654,629)	681,655
Equity in earnings of subsidiaries	124,416	-	-	(124,416)	-
Deferred income tax expense (benefit)	19,961	42,812	(135,619)	233,060	160,214
Debt extinguishment costs	2,844	-	-	-	2,844
Gain on mark-to-market derivative contracts	(81,981)	-	-	-	(81,981)
Loss on investment measured at fair value	52,675	-	-	-	52,675
Non-cash compensation	37,042	12,151	-	-	49,193
Other non-cash items	1,272	(6,898)	67	-	(5,559)
Change in assets and liabilities from operating activities					
Accounts receivable and other assets	(48,878)	(9,937)	1,086	-	(57,729)
Accounts payable and other liabilities	56,840	(4,887)	7,133	-	59,086
Income taxes receivable/payable	43,678	-	-	-	43,678
Net cash provided by operating activities	627,537	442,599	40,618	1	1,110,755
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(820,984)	(853,696)	(108,624)	-	(1,783,304)
Acquisition of oil and gas properties	(13,145)	(27,370)	-	-	(40,515)
Proceeds from sales of oil and gas properties, net of costs and expenses	736,228	-	-	-	736,228
Derivative settlements	(55,412)	-	-	-	(55,412)
Other	(8,062)	480	(4,006)	-	(11,588)
Net cash used in investing activities	(161,375)	(880,586)	(112,630)	-	(1,154,591)
CASH FLOWS FROM FINANCING ACTIVITIES					
Borrowings from revolving credit facilities	6,305,300	-	-	-	6,305,300
Repayments of revolving credit facilities	(6,190,300)	-	-	-	(6,190,300)
Principal payments of long-term debt	(1,295,737)	-	-	-	(1,295,737)
Proceeds from issuance of Senior Notes	1,600,000	-	-	-	1,600,000
Costs incurred in connection with financing arrangements	(27,829)	-	(2,410)	-	(30,239)
Purchase of treasury stock	(361,729)	-	-	-	(361,729)
Net proceeds from issuance of noncontrolling interest in the form of preferred stock of subsidiary	-	-	430,246	-	430,246
Distributions to holders of noncontrolling interest in the form of preferred stock of subsidiary	-	-	(1,050)	-	(1,050)
Investment in and advances to affiliates	(498,707)	437,985	60,691	31	-
Other	9	-	32	(32)	9
Net cash (used in) provided by financing activities	(468,993)	437,985	487,509	(1)	456,500
Net (decrease) increase in cash and cash equivalents	(2,831)	(2)	415,497	-	412,664
Cash and cash equivalents, beginning of period	6,020	8	406	-	6,434
Cash and cash equivalents, end of period	$ 3,189	$ 6	$ 415,903	$ -	$ 419,098

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)	$ (63,186)	$ 199,761	$ 103,265
Items not affecting cash flows from operating activities					
Depreciation, depletion, amortization, accretion and impairment	218,905	427,448	63,780	(99,540)	610,593
Equity in earnings of subsidiaries	119,427	68	-	(119,495)	-
Deferred income tax (benefit) expense	(326,269)	469,426	30,296	20,382	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	(24,221)	(23,356)	1,471	-	(46,106)
Accounts payable and other liabilities	12,449	(42,229)	(1,571)	-	(31,351)
Income taxes receivable/payable	(33,119)	-	-	-	(33,119)
Net cash provided by operating activities	175,721	704,653	30,988	1,108	912,470
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(198,177)	(679,918)	(170,763)	-	(1,048,858)
Acquisition of oil and gas properties	(590,116)	35,431	-	-	(554,685)
Proceeds from sales of oil and gas properties	73,845	120	-	-	73,965
Derivative settlements	(29,921)	-	-	-	(29,921)
Other	(4,007)	(6,115)	(5,687)	-	(15,809)
Net cash used in investing activities	(748,376)	(650,482)	(176,450)	-	(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	(90,042)	(54,174)	145,324	(1,108)	-
Other	184	-	-	-	184
Net cash provided by (used in) financing activities	577,371	(54,174)	145,324	(1,108)	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)	$(164,770)	$ 1,213,980	$ 136,305
Items not affecting cash flows from operating activities					
Depreciation, depletion, amortization, accretion and impairment	212,128	1,870,260	241,822	(1,902,630)	421,580
Equity in earnings of subsidiaries	18,612	1,041	-	(19,653)	-
Deferred income tax (benefit) expense	(421,089)	(306,910)	55,480	708,303	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	(77,302)	54,588	(3,126)	-	(25,840)
Accounts payable and other liabilities	(13,273)	(35,007)	1,174	-	(47,106)
Income taxes receivable/payable and prepaid	(108,227)	-	-	-	(108,227)
Net cash (used in) provided by operating activities	(178,828)	546,657	131,217	-	499,046
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(287,827)	(918,108)	(422,422)	-	(1,628,357)
Acquisition of oil and gas properties	-	(1,159,939)	-	-	(1,159,939)
Proceeds from sales of oil and gas properties	-	-	-	-	-
Derivative settlements	1,522,412	-	-	-	1,522,412
Other	(3,665)	(487)	(10,363)	-	(14,515)
Net cash provided by (used in) investing activities	1,230,920	(2,078,534)	(432,785)	-	(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	(1,831,487)	1,531,603	299,884	-	-
Other	57	-	-	-	57
Net cash (used in) provided by financing activities	(1,360,150)	1,531,603	299,884	-	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

Note 17 — Quarterly Financial Data (Unaudited)

The following table shows summary financial data for 2011 and 2010 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2011					
Revenues	$ 430,314	$ 514,785	$ 501,848	$ 517,541	$ 1,964,488
Income from operations	133,788	186,095	168,552	102,114	590,549
Net income (loss) attributable to common stockholders	70,979	124,892	(88,296)	97,704	205,279
Basic earnings per common share	0.50	0.88	(0.62)	0.70	1.45
Diluted earnings per common share	0.49	0.87	(0.62)	0.69	1.44
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

Note 18 — Oil and Natural Gas Activities

Investment

At December 31, 2011 and 2010, we owned 51.0 million shares of McMoRan common stock, approximately 31.6% and 32.4%, respectively, of its 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 7 – 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,		
	2011	2010	2009
Consolidated entities			
Property acquisition costs			
Unproved properties	$ 36,562	$ 612,471	$ 1,121,644
Proved properties	9,236	48,078	5,072
Exploration costs	1,147,858	719,004	1,309,396
Development costs	708,519	363,242	272,820
	$ 1,902,175	$ 1,742,795	$ 2,708,932
Entity's share of equity investee (1)			
Property acquisition costs			
Unproved properties	$ 15,523		
Proved properties	-		
Exploration costs	175,802		
Development costs	17,190		
	$ 208,515		

(1) Amounts relate to our equity investment in McMoRan acquired 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 $77.1 million, $68.0 million and $67.3 million in 2011, 2010 and 2009, respectively, and capitalized interest expense of $115.4 million, $128.0 million and $113.8 million in 2011, 2010 and 2009, respectively. We had no international exploration costs in 2011; in 2010 and 2009, our international exploration costs, primarily in offshore Vietnam, were $1.7 million and $42.3 million, respectively.

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 terminated 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.

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 depreciation, depletion and amortization, or DD&A, and impairment (in thousands):

	December 31,	
	2011	2010
Consolidated entities		
Property subject to amortization	$ 12,016,252	$ 9,975,056
Accumulated DD&A and impairment	(6,823,722)	(6,176,007)
	$ 5,192,530	$ 3,799,049
Entity's share of equity investee (1)		
Unproved properties	$ 497,955	$ 341,625
Proved properties	805,264	789,584
Accumulated DD&A and impairment	(613,740)	(552,682)
	$ 689,479	$ 578,527

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

Our average DD&A rate per BOE was $17.76, $15.87 and $12.79 in 2011, 2010 and 2009, 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	2011	2010 (1)	2009 (2)	Prior
Acquisition costs	$ 2,148,839	$ 29,249	$ 799,200	$ 917,214	$ 403,176
Exploration costs	55,987	43,755	9,506	896	1,830
Capitalized interest	204,623	81,367	83,867	32,043	7,346
	$ 2,409,449	$ 154,371	$ 892,573	$ 950,153	$ 412,352

(1) Includes amounts attributable to our Eagle Ford Shale acquisition in the fourth quarter of 2010. See Note 2 – Acquisitions.
(2) Includes amounts attributable to the September 2009 pre-payment of the Haynesville Carry associated with the 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 57% of the costs not subject to amortization at December 31, 2011 will be transferred to the amortization base over the next five years and the remainder in the next seven to ten years.

Approximately 21% of our total net undeveloped acreage is covered by leases that will expire from 2012 to 2014. 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. Over 85% of our acreage in the Haynesville Shale and over 25% of our acreage in the Eagle Ford Shale is currently held by production or held by operations and future plans include drilling or extending leases on our remaining acreage.

During the third quarter of 2011, we determined not to develop the Friesian prospect and the lease terminated by its terms. The accumulated costs of approximately $460 million associated with the project were transferred to the full cost pool.

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 pre-tax operating results (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Consolidated entities			
Revenues from oil and gas producing activities	$1,964,488	$1,544,595	$1,187,130
Production costs	(558,240)	(447,772)	(426,103)
Depreciation, depletion, amortization and accretion	(664,892)	(535,239)	(405,597)
Impairment of oil and gas properties	-	(59,475)	-
Income tax expense	(277,860)	(188,190)	(133,464)
Results of operations from producing activities for consolidated entities (excluding general and administrative and interest costs)	$ 463,496	$ 313,919	$ 221,966
Entity's share of equity investee (1)			
Revenues from oil and gas producing activities	$ 171,370		
Production and delivery costs	(65,197)		
Exploration expenses	(25,830)		
Depreciation, depletion, amortization and accretion	(74,820)		
Impairment of oil and gas properties	(22,477)		
Insurance recoveries	28,780		
Gain on sale of oil and gas properties	284		
Income tax expense	-		
Results of operations from producing activities for equity investee (excluding general and administrative and interest costs)	$ 12,110		

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010. 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, 2011. All of our reserves are located in the United States. The following table sets forth certain information with respect to our proved reserves that for 2011 are based upon (1) reserve reports prepared by the independent petroleum engineers of Netherland, Sewell & Associates, Inc., or NSA (95% of proved reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum engineer (5% of proved reserve volumes). In 2010, our proved reserves were based upon (1) reserve reports prepared by the independent petroleum engineers of NSA and Ryder Scott Company L.P., or Ryder Scott (99% of proved reserve volumes) and (2) reserve volumes prepared by us, which were not audited by an independent petroleum engineer (1% of proved reserve volumes). In 2009, our proved reserves were based upon reserve reports prepared by NSA and Ryder Scott.

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. As of February 2012, the twelve-month average of the first-day-of-the-month reference price for natural gas has declined from $4.12 per MMBtu at year-end 2011 to $3.86 per MMBtu, while the comparable price for oil has increased from $95.99 per Bbl at year-end 2011 to $97.28 per Bbl.

Historically, the market price for California crude oil differs from the established market indices in the United States due principally to the higher transportation and refining costs associated with heavy oil. Recently, however, the market price for California crude oil has strengthened relative to NYMEX and WTI primarily due to world demand and declining domestic supplies of both Alaskan and California crude oil. Approximately 53% of our 2011 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, 2011.

	Oil (MBbl)	Gas (MMcf)	(MBOE)
2011			
Consolidated entities			
Proved Reserves			
Beginning balance	223,268	1,157,070	416,113
Revisions of previous estimates	12,295	(64,972)	1,466
Extensions, discoveries and other additions	36,436	232,872	75,248
Improved recovery	-	-	-
Purchase of reserves in-place	1,382	17,454	4,291
Sale of reserves in-place	(11,479)	(229,536)	(49,735)
Production	(17,872)	(111,577)	(36,468)
Ending balance	244,030	1,001,311	410,915
Proved Developed Reserves, December 31	151,480	454,248	227,188
Proved Undeveloped Reserves, December 31	92,550	547,063	183,727
Entity's share of equity investee (1)			
Proved Reserves			
Beginning balance	4,600	60,828	14,738
Revisions of previous estimates	2,081	829	2,219
Extensions, discoveries and other additions	5	611	107
Improved recovery	-	-	-
Purchase of reserves in-place	-	-	-
Sale of reserves in-place	-	-	-
Production	(1,223)	(14,220)	(3,593)
Ending balance	5,463	48,048	13,471
Proved Developed Reserves, December 31	4,921	39,066	11,432
Proved Undeveloped Reserves, December 31	542	8,982	2,039

Table continued on following page.

	Oil (MBbl)	Gas (MMcf)	(MBOE)
2010			
Consolidated entities			
Proved Reserves			
Beginning balance	214,030	873,108	359,548
Revisions 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
Revisions of previous estimates	204	3,632	809
Extensions, discoveries and other additions	-	-	-
Improved recovery	-	-	-
Purchase of reserves in-place	360	15,091	2,875
Sale of reserves in-place	(72)	(45)	(79)
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
2009			
Proved Reserves			
Beginning balance (2)	177,707	686,357	292,100
Revisions 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

(1) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010.
(2) Reserve estimates as of January 1, 2009 are calculated using year-end reference prices adjusted for location and quality differentials as required by SEC reporting rules at December 31, 2008.

Revisions of Previous Estimates

In 2011, we had net positive revisions of 1 MMBOE. Positive revisions of 21 MMBOE were primarily related to higher realized oil prices principally at our California properties. Negative revisions of 20 MMBOE were mostly related to lower gas prices, primarily at our Panhandle properties prior to the divestment in December 2011.

In 2010, we had net 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.

Purchases of Reserves in-Place

In 2011, proved reserves acquired in the Texas Panhandle were 4 MMBOE. These proved reserves were subsequently divested in December 2011.

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.

Extensions, Discoveries and Other Additions

In 2011, we had a total of 75 MMBOE of extensions and discoveries, including 25 MMBOE in the Haynesville Shale and 22 MMBOE in the Eagle Ford Shale resulting from successful drilling during 2011 that extended and developed our proved acreage and 19 MMBOE in the deepwater Gulf of Mexico resulting from sanctioning of the Lucius project.

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.

Sales of Reserves in-Place

In 2011, we had a total of 50 MMBOE of divestments, which were primarily from our Panhandle and South Texas properties.

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.

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,		
	2011	2010	2009
Consolidated entities			
Future cash inflows	$ 29,502,864	$ 21,151,315	$ 14,623,292
Future development costs	(4,017,365)	(3,290,657)	(2,371,383)
Future production expense	(9,543,319)	(7,919,772)	(6,187,933)
Future income tax expense	(4,999,822)	(3,197,758)	(1,521,281)
Future net cash flows	10,942,358	6,743,128	4,542,695
Discounted at 10% per year	(5,808,177)	(3,649,993)	(2,317,856)
Standardized measure of discounted future net cash flows	$ 5,134,181	$ 3,093,135	$ 2,224,839
Entity's share of equity investee(1)			
Future cash inflows	$ 716,829	$ 656,020	
Future development costs	(168,966)	(192,889)	
Future production expense	(179,155)	(165,640)	
Future income tax expense	-	-	
Future net cash flows	368,708	297,491	
Discounted at 10% per year	(106,797)	(86,593)	
Standardized measure of discounted future net cash flows	$ 261,911	$ 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 are made using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. 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, 2011 are discussed in Note 6 – 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, 2011, 2010 and 2009 were $104.59, $72.83 and $54.38 per barrel of oil, respectively, and $4.08, $4.29 and $3.53 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, 2011, are as follows (in thousands):

	December 31,		
	2011	2010	2009
Consolidated entities			
Balance, beginning of year (1)	$ 3,093,135	$ 2,224,839	$ 1,136,374
Sales, net of production expenses	(1,397,901)	(1,090,465)	(761,157)
Net change in sales and transfer prices, net of production expenses	3,085,916	2,030,484	1,568,827
Extensions, discoveries and improved recovery, net of costs	959,491	410,973	87,890
Changes in estimated future development costs	(167,533)	(335,614)	(163,602)
Previously estimated development costs incurred during the year	454,778	267,719	144,017
Purchase of reserves in-place	82,418	41,214	3,198
Sale of reserves in-place	(594,299)	(120,082)	-
Revision of quantity estimates	38,352	338,683	443,344
Accretion of discount	420,957	273,259	188,134
Net change in income taxes	(841,133)	(947,875)	(422,186)
Balance, end of year	$ 5,134,181	$ 3,093,135	$ 2,224,839
Entity's share of equity investee (2)			
Balance, beginning of year	$ 205,691		
Sales, net of production expenses	(105,965)		
Changes in prices	46,514		
Discoveries and extensions, less related costs	1,881		
Changes in estimated future development costs and other	(34,060)		
Previously estimated development costs incurred during the year	65,651		
Purchase of reserves in-place	-		
Sale of reserves in-place	-		
Revision of quantity estimates	61,630		
Accretion of discount	20,569		
Net change in income taxes	-		
Balance, end of year	$ 261,911		

(1) Reserve estimates as of January 1, 2009 are calculated using year-end reference prices adjusted for location and quality differentials as required by the SEC reporting rules at December 31, 2008.

(2) Amounts relate to our equity investment in McMoRan acquired on December 30, 2010. Our proportionate share of McMoRan's changes in the standardized measure for the year ended December 31, 2010 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.

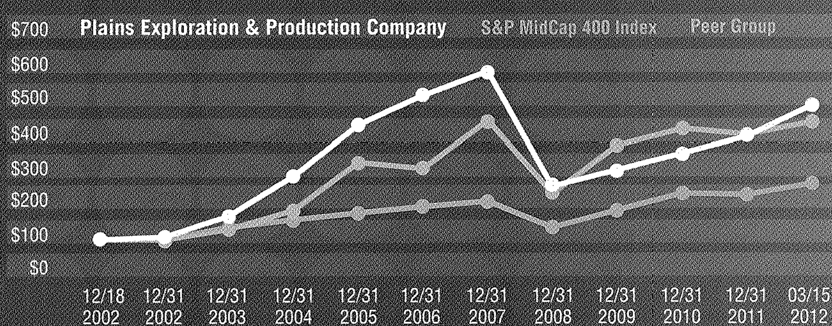
COMPARISON OF SHAREHOLDER RETURN

The following graphs compare 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., Pioneer Natural Resources Company, Range Resources Corporation, SandRidge Energy, Inc. and Ultra Petroleum Corp.

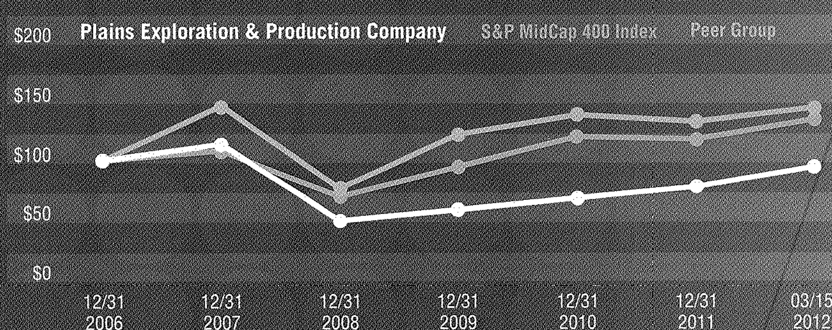
The following graphs cover the period from December 18, 2002, the date PXP's common stock started trading, through March 15, 2012, as well as a 5-year and 3-year time period. Each graph assumes that $100 was invested on the beginning date noted on the graph and that any dividends were reinvested. No dividends have been declared or paid on PXP's common stock. Shareholder returns over the periods indicated should not be considered indicative of future shareholder returns.

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

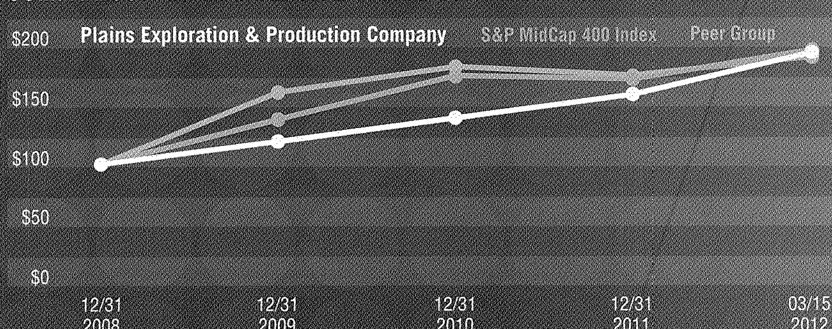
COMPARISON OF CUMULATIVE TOTAL RETURN SINCE INCEPTION



COMPARISON OF CUMULATIVE FIVE YEAR TOTAL RETURN



COMPARISON OF CUMULATIVE THREE YEAR TOTAL RETURN



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 and hydraulic fracturing;
- the effects of future laws and governmental regulation that result from the Macondo accident and oil spill in the U.S. Gulf of Mexico;
- the value of the common stock of McMoRan Exploration Co. and our ability to dispose of those shares;
- 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 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. 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, www.pxp.com. 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) 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.

EXECUTIVE OFFICERS

James C. Flores
Chairman, President and
Chief Executive Officer

Doss R. Bourgeois
Executive Vice President –
Exploration & Production

Winston M. Talbert
Executive Vice President and
Chief Financial Officer

John F. Wombwell
Executive Vice President and
General Counsel

DIRECTORS

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

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

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

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

Tom H. Delimitros
General Partner
AMT Venture Funds

Thomas A. Fry, III
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.

CORPORATE INFORMATION

Transfer Agent
American Stock Transfer & Trust
6201 15th Avenue, 3rd floor
Brooklyn, New York 11219
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, 2011, is available free of charge on request to:

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

Independent Registered Public Accounting Firm
PricewaterhouseCoopers LLP
1201 Louisiana Street, Suite 2900
Houston, Texas 77002-5678

Corporate Headquarters
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700 Milam, Suite 3100
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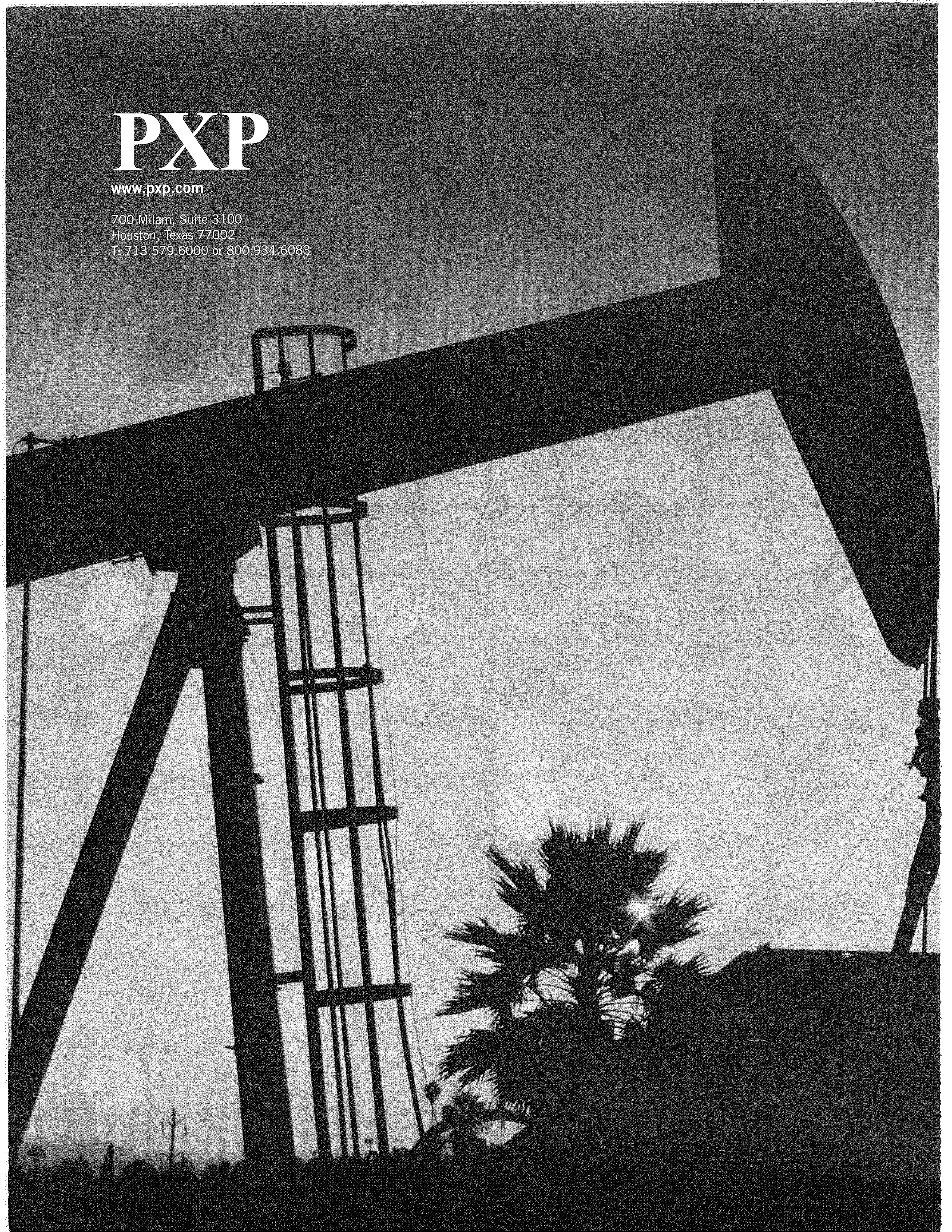

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