POGO PRODUCING CO
Form 10-Q
July 30, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

x Quarterly report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2007 or

o Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission file number 1-7792

POGO PRODUCING COMPANY

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**74-1659398** (I.R.S. Employer Identification No.)
5 Greenway Plaza, Suite 2700 **Houston, Texas** (Address of principal executive offices)	**77046-0504** (Zip Code)

(713) 297-5000

(Registrant s Telephone Number, Including Area Code)

Not Applicable

(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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 x No o

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

Large accelerated filer x Accelerated filer o Non-accelerated filer o

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Common Stock, par value $1.00 per share: 58,653,682 shares as of July 25, 2007

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30, 2007	2006	Six Months Ended June 30, 2007	2006
	(Expressed in millions, except per share amounts)			
Revenue and Other Income				
Oil and gas	$ 220.0	$ 237.0	$ 430.9	$ 480.0
Other	2.9	0.4	3.6	1.2
Total	222.9	237.4	434.5	481.2
Operating Costs and Expenses:				
Lease operating	49.7	47.2	96.6	86.4
General and administrative	27.7	21.5	56.9	41.4
Exploration	5.9	0.5	14.0	1.7
Dry hole and impairment	5.4	12.8	51.7	35.9
Depreciation, depletion and amortization	79.6	64.0	164.0	127.3
Production and other taxes	15.3	16.9	32.9	28.0
Net gain on sales of properties	(127.2)	(308.4)	(129.5)	(308.4)
Other	8.0	5.8	13.1	10.6
Total	64.4	(139.7)	299.7	22.9
Operating Income	158.5	377.1	134.8	458.3
Interest:				
Charges	(40.9)	(36.0)	(83.7)	(64.3)
Income		0.1	0.1	0.3
Capitalized	20.5	18.7	39.9	34.8
Commodity Derivative Expense	(1.5)	(7.1)	(4.6)	(3.8)
Income from Continuing Operations Before Taxes	136.6	352.8	86.5	425.3
Income Tax Expense	(39.7)	(16.2)	(24.2)	(42.8)
Income from Continuing Operations	96.9	336.6	62.3	382.5
Income (Loss) from Discontinued Operations, net of tax	(141.7)	25.3	(128.3)	46.9
Net Income (Loss)	$ (44.8)	$ 361.9	$ (66.0)	$ 429.4
Earnings (Loss) per Common Share:				
Basic				
Income from Continuing Operations	$ 1.68	$ 5.87	$ 1.08	$ 6.67
Income (Loss) from Discontinued Operations, net of tax	(2.46)	0.44	(2.22)	0.81
Net Income (Loss)	$ (0.78)	$ 6.31	$ (1.14)	$ 7.48
Diluted				
Income from Continuing Operations	$ 1.65	$ 5.81	$ 1.06	$ 6.60
Income (Loss) from Discontinued Operations, net of tax	(2.42)	0.44	(2.19)	0.81
Net Income (Loss)	$ (0.77)	$ 6.25	$ (1.13)	$ 7.41
Dividends per Common Share	$ 0.075	$ 0.075	$ 0.15	$ 0.15
Potential Common Shares Outstanding:				
Basic	57,817	57,385	57,776	57,366
Diluted	58,577	57,930	58,501	57,948

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheets (Unaudited)

	June 30, 2007	December 31, 2006
	(Expressed in millions)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 20.3	$ 22.7
Accounts receivable	89.6	103.9
Other receivables	46.4	47.6
Federal income tax receivable		58.0
Inventories tubulars	16.0	18.5
Commodity derivative contracts		10.9
Assets from discontinued operations	103.1	96.5
Other	4.1	10.1
Total current assets	279.5	368.2
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	4,221.0	5,056.6
Unevaluated properties	323.4	301.8
Other, at cost	45.2	43.2
	4,589.6	5,401.6
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,204.1)	(1,619.8)
Other	(32.8)	(30.5)
	(1,236.9)	(1,650.3)
Property and equipment, net	3,352.7	3,751.3
Other Assets:		
Commodity derivative contracts		5.0
Assets from discontinued operations	2,946.6	2,819.5
Other	26.0	27.1
	2,972.6	2,851.6
	$ 6,604.8	$ 6,971.1

See accompanying notes to consolidated financial statements.

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	June 30, 2007 (Expressed in millions, except share amounts)	December 31, 2006
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable operating activities	$ 109.6	$ 107.6
Accounts payable investing activities	58.0	74.2
Income taxes payable	93.6	0.4
Accrued interest payable	24.8	26.0
Accrued payroll and related benefits	10.0	5.1
Commodity derivative contracts	5.6	
Deferred income tax	3.7	7.2
Liabilities from discontinued operations	169.1	162.7
Other	16.6	18.6
Total current liabilities	491.0	401.8
Long-Term Debt	1,837.8	2,319.7
Deferred Income Tax	737.8	804.3
Asset Retirement Obligation	60.5	114.9
Other Liabilities and Deferred Credits	48.1	44.3
Liabilities from Discontinued Operations	737.8	718.7
Total liabilities	3,913.0	4,403.7
Commitments and Contingencies		
Shareholders Equity:		
Preferred stock, $1 par; 4,000,000 shares authorized		
Common stock, $1 par; 200,000,000 shares authorized, 66,015,641 and 65,794,206 shares issued, respectively	66.0	65.8
Additional capital	987.7	971.4
Retained earnings	1,818.1	1,892.9
Accumulated other comprehensive income (loss)	181.3	(1.4)
Treasury stock (7,365,359 shares, at cost)	(361.3)	(361.3)
Total shareholders equity	2,691.8	2,567.4
	$ 6,604.8	$ 6,971.1

See accompanying notes to consolidated financial statements.

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Condensed Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30, 2007	2006
	(Expressed in millions)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 446.3	$ 406.4
Operating, exploration, and general and administrative expenses paid	(205.4)	(113.2)
Interest paid	(43.3)	(58.8)
Income taxes paid		(54.9)
Income tax refund	52.0	2.6
Business interruption insurance proceeds	4.2	6.2
Other	6.4	0.9
Net cash provided by continuing operating activities	260.2	189.2
Net cash provided by discontinued operations	152.8	149.0
Net cash provided by operating activities	413.0	338.2
Cash Flows from Investing Activities:		
Capital expenditures	(370.6)	(213.8)
Purchase of corporations and property	(16.8)	(790.5)
Sale of properties	597.1	463.0
Insurance proceeds	18.6	10.3
Other		(1.0)
Net cash provided by (used in) continuing investing activities	228.3	(532.0)
Net cash used in discontinued operations	(163.5)	(182.3)
Net cash provided by (used in) investing activities	64.8	(714.3)
Cash Flows from Financing Activities:		
Borrowings under senior debt agreements	1,135.0	1,368.0
Payments under senior debt agreements	(1,617.0)	(1,450.0)
Proceeds from 2013 notes		450.0
Purchase of Company stock		(7.7)
Payments to discontinued operations	(8.8)	
Payments of cash dividends on common stock	(8.8)	(8.7)
Payment of debt issue costs		(11.2)
Proceeds from exercise of stock awards	8.5	4.1
Net cash provided by (used in) continuing financing activities	(491.1)	344.5
Net cash provided by discontinued operations	8.8	
Net cash provided by (used in) financing activities	(482.3)	344.5
Effect of exchange rate changes on cash	2.1	0.8
Net decrease in cash and cash equivalents	(2.4)	(30.8)
Cash and cash equivalents from continuing operations, beginning of the year	5.6	8.0
Cash and cash equivalents from discontinued operations, beginning of the year	17.1	49.7
Cash and cash equivalents at the end of the period	$ 20.3	$ 26.9
Reconciliation of net income to net cash provided by operating activities:		
Net income (loss)	$ (66.0)	$ 429.4
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Loss (Income) from discontinued operations, net of tax	128.3	(46.9)
Net gains from the sales of properties	(129.5)	(308.4)
Depreciation, depletion and amortization	164.0	127.3
Dry hole and impairment	51.7	35.9
Commodity derivative contracts	7.9	4.3
Other	(7.6)	(26.2)
Deferred income taxes	(75.0)	(102.3)
Change in operating assets and liabilities	186.4	76.1
Net cash provided by continuing operating activities	260.2	189.2
Net cash provided by discontinued operations	152.8	149.0
Net cash provided by operating activities	$ 413.0	$ 338.2

See accompanying notes to consolidated financial statements.

Consolidated Statement of Shareholders Equity (Unaudited)

	For the Six Months Ended June 30, 2007 Shareholders Equity Shares	Amount
	(Expressed in millions, except share amounts)	
Common Stock:		
$1.00 par-200,000,000 shares authorized		
Balance at beginning of year	65,794,206	$ 65.8
Stock option activity	231,435	0.2
Restricted stock activity	(10,000)	
Issued at end of period	66,015,641	66.0
Additional Capital:		
Balance at beginning of year		971.4
Stock options exercised proceeds		8.2
Stock based compensation excess federal tax benefit		1.2
Stock based compensation restricted stock		6.9
Balance at end of period		987.7
Retained Earnings:		
Balance at beginning of year		1,892.9
Net loss		(66.0)
Dividends ($0.15 per common share)		(8.8)
Balance at end of period		1,818.1
Accumulated Other Comprehensive Income (Loss):		
Balance at beginning of year		(1.4)
Cumulative foreign currency translation adjustment, net of tax		190.0
Deferred post-retirement benefit costs, net of tax		1.4
Change in fair value of commodity derivative contracts, net of tax		(12.1)
Reclassification adjustment for losses on commodity derivative contracts included in net income, net of tax		3.4
Balance at end of period		181.3
Treasury Stock:		
Balance at beginning of year	(7,365,359)	(361.3)
Activity during the period		
Balance at end of period	(7,365,359)	(361.3)
Common Stock Outstanding, at the End of the Period	58,650,282	
Total Shareholders Equity		$ 2,691.8

See accompanying notes to consolidated financial statements.

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Notes to Consolidated Financial Statements (Unaudited)

(1) GENERAL INFORMATION

The consolidated financial statements included herein have been prepared by Pogo Producing Company (the Company) without audit and include all adjustments (of a normal and recurring nature), which are, in the opinion of management, necessary for the fair presentation of interim results. The interim results are not necessarily indicative of results for the entire year. The financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2006.

Certain prior year amounts have been reclassified related to the Company s discontinued operations. Such reclassifications had no effect on the Company s net income or shareholders equity. The Company changed the classification of Net gains on sales of properties from Revenue and Other Income to reflect it as a component of Operating Costs and Expenses for both the current and prior periods. The Company changed the classification of interest capitalized in the Statement of Cash Flows from an operating cash outflow to an investing cash outflow in the fourth quarter of 2006. The Company elected not to change the classification of interest capitalized in the Statement of Cash Flows for periods prior to the fourth quarter of 2006 due to the immateriality of the amounts.

The Company s results for all periods presented reflect its oil and gas exploration, development, and production activities in Canada as discontinued operations. Except where noted and for pro forma earnings per share, the discussions in the following notes relate to the Company s continuing operations only.

On July 17, 2007 Plains Exploration & Production Company (PXP) and the Company entered into a definitive agreement for PXP to acquire the Company in a stock and cash transaction valued at approximately $3.6 billion, based on PXP s closing price on July 16, 2007. Under the terms of the agreement, Pogo stockholders, on an aggregate basis, will receive 0.68201 shares of PXP common stock and $24.88 in cash for each share of the Company s common stock, which represents a total consideration of approximately $60 per share of the Company s common stock based on PXP s closing price on July 13, 2007. Total consideration for all of the issued and outstanding shares of the Company s common stock (excluding treasury shares) is 40 million PXP shares and approximately $1.5 billion in cash. The Company s stockholders have the right to elect to receive cash or stock, subject to proration. In addition, if the 10-day average trading price of PXP shares at the time of the merger varies from the closing price at July 13, 2007, certain adjustment provisions will apply. These adjustment provisions are intended to approximately equalize the then-market value of the PXP shares being issued and the amount of cash being paid to those stockholders who elect to receive all stock or all cash. The aggregate amount of cash being paid and the aggregate number of PXP shares being issued will not change, however. These adjustment provisions are set forth in the merger agreement and will be more fully described in the joint proxy statement/prospectus to be filed by the Company and PXP. The transaction is expected to qualify as a tax-free reorganization under Section 368(a).

This sale is expected to close during the fourth quarter of 2007, subject to customary closing conditions and regulatory approvals, including from the U.S. Securities and Exchange Commission, Federal Trade Commission and Department of Justice, and will be contingent upon approval by PXP stockholders of the issuance of shares of PXP stock to be used as merger consideration and adoption of the merger agreement by the Company s stockholders.

(2) DISCONTINUED OPERATIONS

Under SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS No. 144), the Company classifies assets to be disposed of as held for sale, or, if appropriate, discontinued operations, when the criteria defined in SFAS No. 144 have been met, including a commitment by the Company s management or Board of Directors to sell the assets. On May 28, 2007, the Company entered into an agreement to sell all of the outstanding stock of its wholly-owned subsidiary, Northrock Resources Ltd. (Northrock) for $2.0 billion in cash. The Company expects to complete the sale during the third quarter of 2007 and currently plans to use the proceeds to pay off senior debt and invest the remainder while evaluating debt repayment strategies.

The financial results and financial position for Northrock have been classified as discontinued operations in the Company s financial statements for all periods presented. SFAS No. 144 requires that long-lived assets classified as discontinued operations be measured at the lower of their carrying amount or fair value less cost to sell. The Company has recognized a loss on its investment in Northrock of approximately $184.5 million, which includes $23 million of U.S. income tax expense related to previously unremitted foreign earnings, as part of income (loss) from discontinued operations for both the three and six month periods ended June 30, 2007.

The summarized financial results and financial position of the discontinued operations for the periods presented are as follows:

Operating Results Data

	Three months ended June 30, 2007	2006	Six months ended June 30, 2007	2006
Revenues	$ 141.7	$ 128.8	$ 279.2	$ 258.6
Costs and expenses	(105.0)	(97.5)	(237.3)	(198.1)
Other income	7.4	1.6	8.5	1.7
Income (loss) before income taxes	44.1	32.9	50.4	62.2
Income tax benefit (expense)	(1.3)	(7.6)	5.8	(15.3)
Income before loss from discontinued operations, net of tax	42.8	25.3	56.2	46.9
Loss on Northrock investment, including tax expense of $23 million	(184.5)		(184.5)	
Income(loss) from discontinued operations, net of tax	$ (141.7)	$ 25.3	$ (128.3)	$ 46.9

Financial Position Data

	June 30, 2007	December 31, 2006
Assets of Discontinued Operations		
Accounts receivable	$ 75.0	$ 69.7
Inventories	25.6	24.8
Other current assets	2.5	2.0
Total current assets	103.1	96.5
Property, plant, and equipment, net	2,931.3	2,805.8
Other long-term assets	15.3	13.7
Total assets	$ 3,049.7	$ 2,916.0
Liabilities of Discontinued Operations		
Accounts payable	$ 121.4	$ 158.5
Income taxes payable	43.6	0.4
Other current liabilities	4.1	3.8
Total current liabilities	169.1	162.7
Deferred income tax	686.5	673.7
Asset retirement obligation	48.0	41.4
Other deferred credits	3.3	3.6
Total liabilities	$ 906.9	$ 881.4

(3) OTHER DIVESTITURES

During the three and six months ended June 30, 2007, the Company completed the sale of properties in the onshore Texas and Louisiana areas and the Texas Panhandle for approximately $181.1 million and $190.2 million, respectively. In addition, on June 8, 2007 the Company completed the sale of certain of its federal and state Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment. This transaction, along with the exercise of preferential purchase rights, was for approximately $419.5 million before purchase price adjustments. The proceeds from these sales transactions were used to reduce outstanding debt. The transactions resulted in gains on the sale of properties of $127.2 million and $129.5 million for the three and six months ended June 30, 2007, respectively, which consisted primarily of a gain of $224.9 million on the Gulf of Mexico sale and losses of $7.8 million on the South Texas, Texas Gulf Coast and

Louisiana Gulf Coast sale and $89.4 million on the Texas Panhandle sale. Additionally, the Company recognized impairments for $0.2 million and $34.4 million during the three and six months ended June 30, 2007 on the above properties prior to the completion of the sales.

(4) ACQUISITIONS

2006 - On May 2, 2006, the Company completed the acquisition of Latigo Petroleum, Inc. (Latigo), a privately held corporation for approximately $764.9 million in cash, including transaction costs. The purchase price was funded using cash on hand and debt financing. At the date of purchase, Latigo owned approximately 100,100 net producing acres, plus approximately 304,600 net acres of undeveloped leasehold. Latigo s operations are concentrated in west Texas and the Texas Panhandle with key exploration plays in the Texas Panhandle. The Company acquired Latigo primarily to strengthen its position in domestic exploration and development properties. The following is a calculation and final allocation of purchase price to the acquired assets and liabilities based on their relative fair values:

CALCULATION OF PURCHASE PRICE (IN MILLIONS)		
Cash paid, including transaction costs	$	764.9
Plus fair market value of liabilites assumed:		
Deferred income taxes	205.9	
Other liabilities	55.1	
Total purchase price for assets acquired	$	1,025.9
ALLOCATION OF PURCHASE PRICE (IN MILLIONS)		
Proved oil and gas properties	$	846.9
Unproved oil and gas properties	157.0	
Other assets	22.0	
Total	$	1,025.9

Pro Forma Information

The following summary presents unaudited pro forma consolidated results of operations for the three and six months ended June 30, 2006 as if the acquisition of Latigo had occurred as of January 1, 2006. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of Latigo, such as increased depreciation, depletion and amortization expense resulting from the allocation of fair value to oil and gas properties acquired, increased interest expense on acquisition debt and the related tax effects of these adjustments. The unaudited pro forma information (presented in millions of dollars, except per share amounts) is not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor is it necessarily indicative of future operating results.

Pro Forma:	**Three Months Ended June 30, 2006**		**Six Months Ended June 30, 2006**	
Revenues	$	247.5	$	522.7
Net income	333.3		378.2	
Earnings per share:				
Basic	$	5.81	$	6.59
Diluted	$	5.75	$	6.53

(5) EARNINGS PER SHARE

Earnings per common share (basic earnings per share) are based on the weighted average number of shares of common stock outstanding during the periods. Earnings per share and potential common shares (diluted earnings per share) consider the effect of dilutive securities as set out below. Amounts are expressed in millions, except per share amounts.

	Three Months Ended June 30, 2007	2006	Six Months Ended June 30, 2007	2006
Income (numerator):				
Income from continuing operations	$ 96.9	$ 336.6	$ 62.3	$ 382.5
Income (loss) from discontinued operations, net of tax	(141.7)	25.3	(128.3)	46.9
Net Income (loss) basic and diluted	$ (44.8)	$ 361.9	$ (66.0)	$ 429.4
Weighted average shares (denominator):				
Weighted average shares - basic	57.8	57.4	57.8	57.4
Dilution effect of stock options and unvested restricted stock outstanding at end of period	0.8	0.5	0.7	0.6
Weighted average shares diluted	58.6	57.9	58.5	58.0
Earnings per share:				
Basic:				
Income from continuing operations	$ 1.68	$ 5.87	$ 1.08	$ 6.67
Income (loss) from discontinued operations	(2.46)	0.44	(2.22)	0.81
Basic earnings (loss) per share	$ (0.78)	$ 6.31	$ (1.14)	$ 7.48
Diluted:				
Income from continuing operations	$ 1.65	$ 5.81	$ 1.06	$ 6.60
Income (loss) from discontinued operations	(2.42)	0.44	(2.19)	0.81
Diluted earnings (loss) per share	$ (0.77)	$ 6.25	$ (1.13)	$ 7.41

There were no adjustments for anti-dilutive shares for the three and six months ended June 30, 2007. For the three months ended June 30, 2006, the Company excluded from the diluted earnings per share calculation common stock equivalents totaling 0.2 million shares because their effect on earnings per share was anti-dilutive. There were no adjustments for anti-dilutive shares for the six months ended June 30, 2006.

(6) LONG-TERM DEBT

Long-term debt at June 30, 2007 and December 31, 2006, consists of the following (dollars expressed in millions):

	June 30, 2007	December 31, 2006
Senior debt		
Bank revolving credit agreement:		
LIBOR based loans, borrowings at June 30, 2007 and December 31, 2006 at interest rates of 6.5712% and 6.8524%, respectively	$ 290.0	$ 797.0
LIBOR Rate Advances, borrowings at June 30, 2007 and December 31, 2006 at interest rates of 6.695% and 6.6833%, respectively	100.0	75.0
Total senior debt	390.0	872.0
Senior subordinated debt		
8.25% Senior subordinated notes, due 2011	200.0	200.0
7.875% Senior subordinated notes, due 2013	450.0	450.0
6.625% Senior subordinated notes, due 2015	300.0	300.0
6.875% Senior subordinated notes, due 2017	500.0	500.0
Total senior subordinated debt	1,450.0	1,450.0
Unamortized discount on 2015 Notes	(2.2)	(2.3)
Total debt	1,837.8	2,319.7
Amount due within one year		
Long-term debt	$ 1,837.8	$ 2,319.7

(7) INCOME TAXES

The components of income (loss) from continuing operations before income taxes for the three and six month periods ended June 30, 2007 and 2006 are as follows (expressed in millions):

	Three months ended June 30, 2007	2006	Six months ended June 30, 2007	2006
United States	$ 140.3	$ 348.5	$ 92.1	$ 422.0
Foreign	(3.7)	4.3	(5.6)	3.3
Income (loss) before income taxes	$ 136.6	$ 352.8	$ 86.5	$ 425.3

The components of income tax expense (benefit) for the three and six month periods ended June 30, 2007 and 2006 are as follows (expressed in millions):

	Three months ended June 30, 2007	2006	Six months ended June 30, 2007	2006
Current				
United States	$ 98.4	$ 118.1	$ 98.4	$ 145.0
Foreign			0.8	
Deferred				
United States	(48.3)	10.4	(64.6)	10.0
Foreign (a)	(10.4)	(112.3)	(10.4)	(112.2)
Income tax (benefit) expense	$ 39.7	$ 16.2	$ 24.2	$ 42.8

(a) The foreign income tax benefit in 2006 and 2007 is a result of reductions in the Canadian federal and provincial tax rates. Generally accepted accounting principles (GAAP) require that the entire tax effect of a change in enacted tax rates be allocated to continuing operations.

Total income tax expense (benefit) for the three and six month periods ended June 30, 2007 and 2006, differs from the amounts computed by applying the statutory federal income tax rate to income before taxes as follows (expressed as percent of pretax income):

	Three months ended June 30, 2007		2006		Six months ended June 30, 2007		2006	
Federal statutory income tax rate	35.0	%	35.0	%	35.0	%	35.0	%
Increases (decreases) resulting from:								
Canadian rate change	(7.6	)	(31.8	)	(12.1	)	(26.4	)
State income taxes, net of federal benefits	0.6		1.6		1.1		1.6	
Other	1.1		(0.2	)	4.0		(0.2	)
	29.1	%	4.6	%	28.0	%	10.0	%

As pre-tax book income changes in future quarters, the Company s effective tax rate may increase or decrease. The Company expects to complete the sale of Northrock during the third quarter of 2007. The pending sale resulted in the recognition for financial reporting purposes of U.S. income tax on previously unremitted foreign earnings of approximately $23.0 million. This U.S. tax has been included in the loss on Northrock investment in discontinued operations.

On January 1, 2007, the Company adopted the provisions of FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes. The Company has determined that no uncertain tax positions exist where the Company would be required to make additional tax payments. As a result, the Company has not recorded any additional liabilities for any unrecognized tax benefits as of June 30, 2007.

The Company and its subsidiaries file income tax returns in the U.S. federal and various state and foreign jurisdictions. The Company is no longer subject to U.S. federal, state, or local tax examinations by tax authorities for years prior to 2003. The Company s Canadian subsidiary is no longer subject to examinations by Canadian taxing authorities for years prior to 2002.

The Company s accounting policy is to recognize penalties and interest related to unrecognized tax benefits as income tax expense. The Company does not have an accrued liability for the payment of penalties and interest at June 30, 2007.

(8) ASSET RETIREMENT OBLIGATION

The Company s liability for expected future costs associated with site reclamation, facilities dismantlement, and plugging and abandonment of wells for the six month period ended June 30, 2007 is as follows (in millions):

	2007	
ARO as of January 1,	$ 121.7	
Liabilities incurred during the six months ended June 30,	2.1	
Liabilities settled during the six months ended June 30,	(64.9	)
Accretion expense	4.2	
Balance of ARO as of June 30,	63.1	
Less: current portion of ARO	(2.6	)
Long-term ARO as of June 30,	$ 60.5	

For the three months ended June 30, 2007 and 2006, the Company recognized depreciation expense related to its asset retirement cost (ARC) of $1.6 million and $1.4 million, respectively. For the six months ended June 30, 2007 and 2006, the Company recognized depreciation expense related to its ARC of $3.7 million and $3.8 million, respectively.

(9) SEVERANCE AND RETENTION INCENTIVE PROGRAM

The Company established a Change of Control Severance and Retention Program (the Plan), effective as of January 1, 2007, to provide severance benefits and a retention incentive to employees who are designated by the Plan Administrator as eligible for benefits under the Plan in the event of a Change of Control. Employees who are selected to participate in the Plan will receive retention benefits on the earlier of (i) involuntary termination of employment by the Company, other than for cause, (ii) a change of control, or (iii) December 31, 2007. For the three months and six months ended June 30, 2007, the Company recorded general and administrative expense related to retention benefits of $2.6 million and $5.5 million, respectively.

(10) COMMODITY DERIVATIVES AND HEDGING ACTIVITIES

As of June 30, 2007, the Company held various derivative instruments. During 2005 and 2006, the Company entered into natural gas and crude oil option agreements referred to as collars . Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

During the three and six month periods ended June 30, 2007, the Company recognized pre-tax gains of $0.6 million and $2.5 million, respectively, in its oil and gas revenues related to settled price hedge contracts. During the three and six month periods ended June 30, 2006, the Company recognized a pre-tax gain of $0.1 million and a pre-tax loss of $4.3 million, respectively, in its oil and gas revenues related to settled price hedge contracts. The Company recognized pre-tax losses of $0.1 million and $3.3 million in Other expense due to ineffectiveness on unsettled hedge contracts during the three and six month periods ended June 30, 2007, respectively. The Company recognized pre-tax losses of $1.3 million and $1.6 million in Other expense due to ineffectiveness on unsettled hedge contracts during the three and six month periods ended June 30, 2006, respectively. Unrealized pre-tax losses on derivative instruments of $3.2 million ($2.0 million after taxes) have been reflected as a component of other comprehensive income at June 30, 2007. Based on the fair market value of the hedge contracts as of June 30, 2007, the Company would reclassify additional pre-tax losses of approximately $3.2 million (approximately $2.1 million after taxes) from accumulated other comprehensive income (shareholders equity) to net income during the next twelve months.

The gas derivative contracts are generally settled based upon the average of the reported settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil derivative transactions are generally settled based on the average of the reported settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these contracts is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company s hedging activities as of June 30, 2007 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset/(Liability) (in millions)
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
July 2007 - December 2007	2,760	$ 6.00	$ 12.00	$ (0.3)
July 2007 - December 2007	920	$ 6.00	$ 12.15	$ (0.1)
July 2007 - December 2007	4,600	$ 6.00	$ 12.50	$ (0.4)
July 2007 - December 2007	460	$ 8.00	$ 13.40	$ 0.2
July 2007 - December 2007	1,380	$ 8.00	$ 13.50	$ 0.8
July 2007 - December 2007	460	$ 8.00	$ 13.52	$ 0.3
July 2007 - December 2007	460	$ 8.00	$ 13.65	$ 0.2
January 2008 - December 2008	1,830	$ 8.00	$ 12.05	$ 0.6
January 2008 - December 2008	2,745	$ 8.00	$ 12.10	$ 0.9
January 2008 - December 2008	915	$ 8.00	$ 12.25	$ 0.3
Crude Oil Contracts (Barrels)				
Collar Contracts:				
July 2007 - December 2007	736,000	$ 50.00	$ 75.00	$ (1.8)
July 2007 - December 2007	184,000	$ 50.00	$ 75.25	$ (0.4)
July 2007 - December 2007	1,104,000	$ 50.00	$ 77.50	$ (1.9)
July 2007 - December 2007	92,000	$ 60.00	$ 82.75	$
January 2008 - December 2008	183,000	$ 60.00	$ 80.00	$ (0.4)
January 2008 - December 2008	183,000	$ 60.00	$ 80.05	$ (0.4)
January 2008 - December 2008	183,000	$ 60.00	$ 80.10	$ (0.4)
January 2008 - December 2008	366,000	$ 60.00	$ 80.25	$ (0.8)

(a) MMBtu means million British Thermal Units

Although the Company s collars are effective as economic hedges, the Gulf of Mexico sales, along with the shut-in forecasted hydrocarbon production from the Company s Gulf of Mexico properties prior to the sales (resulting primarily from hurricane activity during the third quarter of 2005) caused certain of the gas and crude oil collar contracts to lose their qualification for hedge accounting under SFAS 133. The Company recognizes changes in the fair value of these contracts in the consolidated statement of income for the period in which the change occurs under the caption Commodity derivative income (expense). The Company recognized realized and unrealized losses related to these contracts of $1.5 million and $4.6 million during the three and six month periods ended June 30, 2007, respectively, and $7.1 million and $3.8 million of realized and unrealized losses for the three and six month periods ended June 30, 2006, respectively. As of June 30, 2007, the Company had the following open collar contracts that no longer qualify for hedge accounting:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Liability (in millions)
Natural Gas Contracts (MMBtu)				
Collar Contracts:				
July 2007 - December 2007	3,680	$ 6.00	$ 12.15	$ (0.4)
July 2007 - December 2007	1,840	$ 6.00	$ 12.20	$ (0.2)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
July 2007 - December 2007	736,000	$ 50.00	$ 77.50	$ (1.3)
July 2007 - December 2007	276,000	$ 60.00	$ 83.00	$ (0.1)
July 2007 - December 2007	92,000	$ 60.00	$ 84.00	$

(11) EMPLOYEE BENEFIT PLANS

The Company has adopted a trusteed retirement plan for its U.S. salaried employees. The benefits are based on years of service and the employee s average compensation for five consecutive years within the final ten years of service that produce the highest average compensation. As of June 30, 2007, the Company has a projected benefit obligation of $15.1 million related to its pension plan. The Company did not make a contribution to the plan during the first six months of 2007; however, the Company is currently evaluating the need for a contribution during the remainder of 2007.

Although the Company has no obligation to do so, the Company currently provides full medical benefits to its retired U.S. employees and dependents. For current employees, the Company assumes all or a portion of post-retirement medical and term life insurance costs based on the employee s age and length of service with the Company. The post-retirement medical plan has no assets and is currently funded by the Company on a pay-as-you-go basis.

The Company s net periodic benefit cost for its benefit plans is comprised of the following components (in millions of dollars):

	Retirement Plan Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Service cost	$ 1.6	$ 1.1	$ 2.9	$ 2.2
Interest cost	1.0	0.7	1.6	1.3
Expected return on plan assets	(1.0)	(0.7)	(1.7)	(1.4)
Amortization of prior service cost			0.1	
Amortization of net loss	0.5	0.4	1.0	0.9
	$ 2.1	$ 1.5	$ 3.9	$ 3.0

	Post-Retirement Medical Plan Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Service cost	$ 0.9	$ 0.5	$ 1.5	$ 0.9
Interest cost	0.6	0.3	0.9	0.6
Amortization of prior service cost			0.1	
Amortization of net loss	0.1		0.2	0.1
	$ 1.6	$ 0.8	$ 2.7	$ 1.6

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The assumptions used in the valuation of the Company s employee benefit plans and the target investment allocations have remained the same as those disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2006.

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduced a prescription drug benefit under Medicare (Medicare Part D), as well as a nontaxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. The Company has elected not to reflect changes in the Act in its financial statements since the Company has concluded that the effects of the Act are not a significant event that calls for remeasurement under SFAS 106.

(12) COMPREHENSIVE INCOME (LOSS)

As of the indicated dates, the Company s comprehensive income (loss) consisted of the following (in millions):

	Three Months Ended June 30, 2007	2006	Six Months Ended June 30, 2007	2006
Net income (loss)	$ (44.8)	$ 361.9	$ (66.0)	$ 429.4
Foreign currency translation adjustment, net of tax	171.1	83.2	190.0	75.3
Deferred post-retirement benefit costs, net of tax	0.6		1.4	
Change in fair value of price hedge contracts, net of tax	0.4	(2.9)	(12.1)	19.0
Reclassification adjustment for hedge contract losses included in net income, net of tax	0.5	5.2	3.4	5.4
Comprehensive income (loss)	$ 127.8	$ 447.4	$ 116.7	$ 529.1

(13) INSURANCE RECOVERIES

On February 28, 2007, the Company reached an agreement with its insurers to settle all outstanding claims related to Hurricanes Katrina and Rita. During the first six months of 2007, the Company recorded $4.2 million of business interruption insurance recoveries as a reduction of Other expenses and $18.6 million in property damage recoveries, of which $13.8 million was used to partially offset hurricane-related property damage repair costs recorded in Lease operating expense and $4.8 million reduced a previously accrued insurance receivable.

(14) RECENT ACCOUNTING PRONOUNCEMENTS

On February 15, 2007, the Financial Accounting Standards Board (FASB) issued Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 (SFAS 159). The Statement permits entities to choose to measure eligible financial instruments and certain other items at fair market value, with the objective of improving financial reporting by giving entities the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The Statement is effective for fiscal years beginning after November 15, 2007. The adoption of SFAS 159 is not expected to have a material impact, if any, on the Company s financial statements.

ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations.

This discussion should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations included in the Company s Annual Report on Form 10-K for the year ended December 31, 2006 as well as the risk factors therein. The assets comprising the Company s operations have changed substantially during the periods presented in this report, which affects comparability between those periods of the Company s results of operations and financial condition. The Company acquired Latigo on May 2, 2006, disposed of 50% of its interests in its Gulf of Mexico properties on May 31, 2006, disposed of substantially all of its remaining interests in the Gulf of Mexico on April 23, 2007 (the Gulf of Mexico sales), and on May 28, 2007, entered into a definitive agreement to sell all of the outstanding stock of its wholly-owned subsidiary, Northrock Resources Ltd. (Northrock), which is expected to close during the third quarter of 2007. The financial results of Northrock are classified as discontinued operations in the Company s financial statements for all periods presented. Except where noted, discussions in this report relate to the Company s continuing operations. For summary pro forma results of operations from the Company s continuing operations as if the Latigo acquisition had occurred on January 1, 2006, please refer to Note 2 Acquisitions to the Unaudited Consolidated Financial Statements in this report. Some of the statements in the discussion are Forward Looking Statements and are thus prospective. As further discussed in the Company s Annual Report on Form 10-K for the year ended December 31, 2006, these forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from future results expressed or implied by such forward-looking statements.

Executive Overview

Below is an overview of the significant transactions and financial matters which occurred during the second quarter of 2007.

Definitive Agreement for the Sale of Pogo Producing Company

On July 17, 2007 Plains Exploration & Production Company (PXP) and the Company entered into a definitive agreement for PXP to acquire the Company in a stock and cash transaction valued at approximately $3.6 billion, based on PXP s closing price on July 16, 2007. Under the terms of the agreement, Pogo stockholders, on an aggregate basis, will receive 0.68201 shares of PXP common stock and $24.88 in cash for each share of the Company s common stock, which represents a total consideration of approximately $60 per share of the Company s common stock based on PXP s closing price on July 13, 2007. Total consideration for all of the issued and outstanding shares of the Company s common stock (excluding treasury shares) is 40 million PXP shares and approximately $1.5 billion in cash. The Company s stockholders have the right to elect to receive cash or stock, subject to proration. In addition, if the 10-day average trading price of PXP shares at the time of the merger varies from the closing price at July 13, 2007, certain adjustment provisions will apply. These adjustment provisions are intended to approximately equalize the then-market value of the PXP shares being issued and the amount of cash being paid to those stockholders who elect to receive all stock or all cash. The aggregate amount of cash being paid and the aggregate number of PXP shares being issued will not change, however. These adjustment provisions are set forth in the merger agreement and will be more fully described in the joint proxy statement/prospectus to be filed by the Company and PXP. The transaction is expected to qualify as a tax-free reorganization under Section 368(a).

This sale is expected to close during the fourth quarter of 2007, subject to customary closing conditions and regulatory approvals, including from the U.S. Securities and Exchange Commission, Federal Trade Commission and Departement of Justice, and will be contingent upon approval by PXP stockholders of the issuance of shares of PXP stock to be used as merger consideration and adoption of the merger agreement by the Company s stockholders.

Sale of Northrock Resources

On May 28, 2007, the Company announced that its Board of Directors had approved a definitive agreement under which the Company would sell all of the outstanding stock of Northrock, for $2.0 billion in cash to Abu Dhabi National Energy Company PJSC (TAQA). This sale is expected to close during the third quarter of 2007, subject to customary closing conditions and regulatory approvals. The Company recognized an after tax loss of $184.5 million from the pending sale, which is reflected as part of Loss from Discontinued Operations, net of tax.

The sale of Northrock includes properties located largely in Alberta, Saskatchewan and the Northwest Territories. Northrock properties currently produce approximately 29,000 barrels of oil equivalent per day (boepd) and contain approximately 706 billion cubic feet equivalent (bcfe) of estimated proven reserves as of December 31, 2006. About 51% of the production and 55% of the Northrock reserves are oil. The Company currently plans to use the proceeds to pay off senior debt and invest the remainder while evaluating debt repayment strategies. The results of Northrock have been reflected in the financial statements as discontinued operations.

On a pro forma basis upon closing of the sale of Northrock, and following the close of other previously announced transactions (except the acquisition of the Company by PXP), the Company expects that it will have an onshore U.S. asset base with proven reserves of approximately 1.3 tcfe (or 217 million barrels of oil equivalent) with approximately 81% in the Western U.S. Division, (which includes 720 bcfe in the Permian Basin and Texas Panhandle, 244 bcfe in the Rockies and 101 bcfe in the San Juan Basin) and 19% in the onshore Gulf Coast Division, including 180 bcfe in south Texas. The Company announced that its reserve mix would be approximately 65% natural gas with a reserve life of 12 years.

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Closed Sale of Onshore Texas and Louisiana and Offshore Gulf of Mexico Properties

During the first quarter of 2007, the Company sold properties in the onshore Texas and Louisiana areas for approximately $100 million as part of the Company s strategic alternative initiative to enhance shareholder value. Two transactions totaling approximately $9.1 million closed during the first quarter, while transactions totaling approximately $90.6 million closed in April. During the second quarter of 2007, the Company also completed the sale of properties in the Texas Panhandle for approximately $90.5 million. In addition, on June 8, 2007, the Company completed the sale of properties located in the Gulf of Mexico for approximately $419.5 million. The transactions resulted in gains on the sale of properties of $127.2 million and $129.5 million for the three and six months ended June 30, 2007, respectively, which consisted primarily of a gain of approximately $224.9 on the Gulf of Mexico sale and losses of approximately $7.8 million on the South Texas, Texas Gulf Coast and Louisiana Gulf Coast sale and approximately $89.4 million on the Texas Panhandle sale. Additionally, the Company recognized impairments for $0.2 million and $34.4 million during the three and six months ended June 30, 2007 on the above properties prior to the completion of the sales.

Second Quarter Results

Total revenue for the second quarter of 2007 for continuing operations was $222.9 million and income from continuing operations totaled $96.9 million, or $1.68 per share. Operating cash flow from continuing operations totaled $91.2 million. As of June 30, 2007, long-term debt was approximately $1.8 billion, decreasing from March 31, 2007 by approximately $0.5 billion, primarily due to repayments using the cash proceeds of approximately $582.7 million from the Company s sales of interests in the onshore Texas and Louisiana areas, the Texas Panhandle, and the Gulf of Mexico. The Company s debt to total capitalization ratio, an indicator of a company s financial strength, was 40.6% at June 30, 2007. Cash and cash equivalents decreased from $22.7 million at December 31, 2006 to approximately $20.3 million at June 30, 2007.

Oil and gas capital and exploration expenditures for the second quarter were approximately $186.7 million. Exploration and development drilling totaled approximately $133.1 million during the second quarter. For the second quarter of 2007, the Company drilled 86 wells with 80 successfully completed, a 93% success rate.

The Company recognized a net gain on property sales of $127.2 million from the sale of its Gulf of Mexico operations and properties in the Texas Panhandle and Texas and Louisiana Gulf Coasts. The Company incurred an after-tax loss of $184.5 million from the pending sale of its Canadian subsidiary, Northrock Resources, Ltd., which is reflected as part of Loss from Discontinued Operations, net of tax.

2007 Capital Budget

The Company has established a $720 million exploration and development budget (excluding property acquisitions) for 2007. The Company expects to spend approximately $199 million on exploration and $521 million on development activities. The capital budget calls for the drilling of approximately 370 wells during 2007, including wells in the United States, Canada, and New Zealand.

Exposure to Oil and Gas Prices and Availability of Oilfield Services

Oil and natural gas prices have historically been seasonal, cyclical and volatile. Prices depend on many factors that the Company cannot control such as weather and economic, political and regulatory conditions. The average prices the Company is currently receiving for production are higher than historical average prices. A future drop in oil and gas prices could have a serious adverse effect on cash flow and profitability. Sustained periods of low prices could have a serious adverse effect on the Company s operations and financial condition. Additionally, the cost of drilling, completing and operating wells and installing facilities and pipelines is often uncertain and have each increased substantially. The market for oil field services is currently very competitive and shortages or delays in delivery or availability of equipment or fabrication yards could impact the Company s ability to conduct oil and gas drilling and completion operations.

Results of Operations

Oil and Gas Revenues

The Company s oil and gas revenues for the second quarter of 2007 were $220.0 million, a decrease of approximately 7% from oil and gas revenues of $237.0 million for the second quarter of 2006. The Company s oil and gas revenues for the first six months of 2007 were $430.9 million, a decrease of approximately 10% from oil and gas revenues of $480.0 million from the first six months of 2006.The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in millions) between 2007 and 2006:

	2nd Qtr. 2007 Compared to 2nd Qtr. 2006	1st 6 Mos. 2007 Compared to 1st 6 Mos. 2006
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas		
Price	$ 9.2	$ (3.5)
Production	3.9	3.0
	13.1	(0.5)
Crude oil and condensate		
Price	(14.3)	(13.7)
Production	(18.3)	(36.1)
	(32.6)	(49.8)
Natural gas liquids		
Price	1.7	2.7
Production	0.9	(1.5)
	2.6	1.2
Decrease in oil and gas revenues	$ (16.9)	$ (49.1)

The most significant cause for the increase in natural gas production for the three and six months ended June 30, 2007 compared to the same periods in 2006 was the acquisition of Latigo on May 2, 2006, which increased natural gas revenues by approximately $7.1 million and $24.6 million, in the respective 2007 periods; these increases were only partially offset by the sale of the Company s remaining interests in the Gulf of Mexico on June 8, 2007, which decreased natural gas revenues by approximately $9.0 million and $22.4 million, respectively. The most significant cause for the decrease in oil and condensate production for the three and six months ended June 30, 2007 compared to the same periods in 2006 was also the sale of the Company s interests in the Gulf of Mexico, which decreased oil and condensate revenues by approximately $33.5 million and $67.1 million, in the respective 2007 periods; these decreases were only partially offset by the Latigo acquisition, which increased oil and condensate revenues by approximately $10.2 million and $28.5 million, respectively. The following tables reflect the relative changes in hydrocarbon volumes and prices:

	2nd Quarter 2007	2006	% Change 2006 to 2007	1st Six Months 2007	2006	% Change 2006 to 2007
Comparison of Increases (Decreases) in:						
Natural Gas						
Average prices (per Mcf) (a)	**$ 6.43**	$ 5.90	**9 %**	**$ 6.44**	$ 6.53	**(1)%**
Average daily production volumes (MMcf per day) (a):	**199.1**	192.4	**3 %**	**202.6**	200.0	**1 %**

(a) Price hedging activity increased the average price of the Company s natural gas production during the second quarter and first six months of 2007 by $0.03 and $0.05 per Mcf, respectively. Price hedging activity increased the average price of the Company s natural gas production during the second quarter of 2006 by less than $0.01 per Mcf and reduced the average price of the Company s natural gas production during the first six months of 2006 by $0.09 per Mcf. MMcf is an abbreviation for million cubic feet.

	2nd Quarter 2007	2006	% Change 2006 to 2007	1st Six Months 2007	2006	% Change 2006 to 2007
Comparison of Increases (Decreases) in:						
Crude Oil and Condensate						
Average prices (per Bbl) (a)	**$ 61.90**	$ 70.38	**(12)%**	**$ 58.37**	$ 62.39	**(6)%**
Average daily production volumes (Bbls per day) (a):	**15,352**	18,594	**(17)%**	**15,518**	18,932	**(18)%**
Natural Gas Liquids						
Average prices (per Bbl) (a)	**$ 43.19**	$ 38.73	**12 %**	**$ 39.17**	$ 35.82	**9 %**
Average daily production volumes (Bbls per day) (a):	**4,368**	4,143	**5 %**	**4,353**	4,568	**(5)%**
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)	19,720	22,737	**(13)%**	19,871	23,500	**(15)%**

(a) During the second quarter of 2007, price hedging activity had no effect on the average price of the Company s crude oil and condensate production; during the first six months of 2007 it increased the average price by $0.16 per barrel. Price hedging activity had no effect on the average price of the Company s crude oil and condensate production during the second quarter and first six months of 2006. Bbls is an abbreviation for barrels.

Other Income

Other income is derived from sources other than the current production of hydrocarbons. This income includes miscellaneous items, income from salt-water disposal activities and pipeline imbalance settlements. During both the three and six months ended June 30, 2007, the Company recognized a gain of $2.2 million from the assignment of an accounts receivable (which had been fully reserved) to a third party.

Costs and Expenses

	2nd Quarter 2007	2006	% Change 2006 to 2007	1st Six Months 2007	2006	% Change 2006 to 2007
	(Expressed in millions, except DD&A statistics)					
Comparison of Increases (Decreases) in:						
Lease Operating Expenses	**$ 49.7**	$ 47.2	**5 %**	**$ 96.6**	$ 86.4	**12 %**
General and Administrative Expenses	**$ 27.7**	$ 21.5	**29 %**	**$ 56.9**	$ 41.4	**37 %**
Exploration Expenses	**$ 5.9**	$ 0.5	**1080 %**	**$ 14.0**	$ 1.7	**724 %**
Dry Hole and Impairment Expenses	**$ 5.4**	$ 12.8	**(58)%**	**$ 51.7**	$ 35.9	**44 %**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 79.6**	$ 64.0	**24 %**	**$ 164.0**	$ 127.3	**29 %**
DD&A rate	**$ 2.70**	$ 2.09	**30 %**	**$ 2.76**	$ 2.01	**37 %**
MMcfe produced	**78,067**	62,398	**25 %**	**58,244**	61,724	**(6)%**
Production and Other Taxes	**$ 15.3**	$ 16.9	**(9)%**	**$ 32.9**	$ 28.0	**18 %**
Net Gains on Sales of Properties	**$ (127.2)**	$ (308.4)	**(59)%**	**$ (129.5)**	$ (308.4)	**(58)%**
Other	**$ 8.0**	$ 5.8	**38 %**	**$ 13.1**	$ 10.6	**24 %**
Interest						
Charges	**$ (40.9)**	$ (36.0)	**14 %**	**$ (83.7)**	$ (64.3)	**30 %**
Capitalized Interest	**$ 20.5**	$ 18.7	**10 %**	**$ 39.9**	$ 34.8	**14 %**

Commodity Derivative Income (Expense)	**$**	**(1.5**	**)**	$	(7.1	)	**(79**	**)%**	**$**	**(4.6**	**)**	$	(3.8	)	**21**	**%**
Income Tax Expense	**$**	**(39.7**	**)**	$	(16.2	)	**145**	**%**	**$**	**(24.2**	**)**	$	(42.8	)	**(43**	**)%**

Lease Operating Expenses

The increase in lease operating expenses for the three and six months ended June 30, 2007 is primarily related to the inclusion of expenses related to the Company s Latigo operations for such periods, which contributed an additional $5.8 million and $15.0 million in lease operating expenses, respectively. Such increased expense from the Company s Latigo operations along with miscellaneous increases of $4.1 million during the first half of 2007 were partially offset by a decrease in hurricane-related workover activity of $3.6 million and $10.2 million for the three and six months ended June 30, 2007, respectively. The Company expects lease operating expenses to decrease during the remainder of 2007 as the impact of the completed asset sales takes effect.

On a per unit of production basis, the Company s total lease operating expenses increased from an average of $1.58 per Mcfe for the second quarter of 2006 to $1.72 per Mcfe for the second quarter of 2007. For the six months ended June 30, 2007, the Company s total lease operating expenses on a per unit of production basis increased to $1.66 per Mcfe, compared to $1.40 per Mcfe for the first six months of 2006. These increases in unit costs are primarily related to the increased expenses discussed above, compounded by the production impact discussed in Oil and Gas Revenues above.

General and Administrative Expenses

The increase in general and administrative expenses for the second quarter of 2007, compared with the same period in 2006, is related primarily to an increase in retention expenses of $2.6 million, increased employee benefits of $1.7 million, and additional legal and advisory fees of approximately $0.4 million related to the Company s previously announced strategic alternatives process. The increase in general and administrative expenses for the six months ended June 30, 2007, compared to the same period in 2006, is related primarily to an increase in the size of the Company s workforce due to the Latigo acquisition, which added approximately $5.9 million in salary and benefit expenses; an increase in retention expenses of $5.5 million; and increased legal and advisory fees associated with the strategic alternatives process of approximately $1.3 million.

On a per unit of production basis, the Company s general and administrative expenses increased to $0.96 per Mcfe in the second quarter of 2007, up from $0.72 per Mcfe in the second quarter of 2006. For the six months ended June 30, 2007, the Company s general and administrative expenses on a per unit of production basis increased to $0.98 per Mcfe, compared to $0.67 per Mcfe for the first six months of 2006. These increases in unit costs are primarily related to the increased expenses discussed above, compounded by the production impact discussed in Oil and Gas Revenues above.

Exploration Expenses

Exploration expenses consist primarily of rental payments required under oil and gas leases to hold non-producing properties (delay rentals) and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses for the second quarter of 2007 increased from the second quarter of 2006 due to the sale of a partial interest in the Company s New Zealand seismic license to a working interest partner, which lowered 2006 expenses by $4.7 million, and additional seismic expenditures of $3.2 million in 2007 in the Company s Asia/Pacific region, which was partially offset by a decrease in seismic expenditures in the Permian area of $2.1 million and a $1.2 million decrease in delay rentals paid due to the Company s reduced property base. For the six months ended June 30, 2007, exploration expenses increased over the same period of 2006 due to the aforementioned New Zealand seismic license sale, which decreased 2006 expenses by $4.7 million, and additional seismic expenditures of $7.5 million and $3.2 million in the Company s Gulf Coast and Asia/Pacific regions, respectively; these increases were partially offset by a decrease in seismic expenditures in the Permian area of $1.8 million and a $1.2 million decrease in delay rentals paid due to the Company s reduced property base.

Dry Hole and Impairment Expenses

Dry hole and impairment expenses relate to costs of unsuccessful exploratory wells drilled and impairment of oil and gas properties. The decrease in dry hole and impairment expense for the second quarter of 2007, compared to the second quarter of 2006, was the result of decreased impairments discussed below, and a decrease in exploratory dry hole costs incurred from approximately $8.7 million during the second quarter of 2006 to approximately $3.7 million in the second quarter of 2007. Dry hole and impairment expenses increased during the first six months of 2007 from the same period in 2006 primarily due to an increase in impairments (see below), which were only slightly offset by a decrease in exploratory dry hole costs incurred from approximately $25.5 million to $11.6 million, respectively. The Company had approximately $44.2 million of costs attributable to exploratory wells in progress as of June 30, 2007 that, as of July 25, 2007 were either still in progress or pending evaluation.

Generally accepted accounting principles (GAAP) require that if the expected future cash flow of the Company s reserves on a property fall below the cost that is recorded on the Company s books, the property must be impaired and written down to its fair value. Depending on market conditions, including the prices for oil and natural gas, the Company s results of operations, or a pending sale, a similar test may be conducted at any time to determine whether impairments are appropriate. Depending on the results of this test, impairments could be required on some of the Company s properties, and such impairments could have a material negative non-cash impact on the Company s earnings and balance sheet. During the second quarter of 2007 and 2006, the Company recognized impairments on various prospects and leases in the amount of $1.7 million and $4.1 million, respectively. During the six months ended June 30, 2007 and 2006, the Company recognized impairments on various prospects and leases in the amount of $40.0 million and $10.5 million, respectively. Of the 2007 amount, $34.4 million is related to the properties in the Company s Gulf Coast area that were sold, which were required to be measured at the lower of their carrying amount or fair value less cost to sell at the time they were classified as held for sale.

Depreciation, Depletion and Amortization Expenses

The Company s provision for DD&A expense is based on its capitalized costs and is determined on a cost center by cost center basis using the units of production method. Generally, the Company establishes cost centers on the basis of a reasonable aggregation of properties with a common geologic structural feature or stratigraphic condition for its onshore oil and gas activities. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in offshore areas. The increase in the Company s DD&A expenses for the three and six months ended June 30, 2007 compared to the same periods of 2006, resulted primarily from an increase in the Company s composite DD&A rate.

The increase in the composite DD&A rate for all of the Company s producing fields for the three and six months ended June 30, 2007, compared to the 2006 periods, resulted primarily from a decrease in the percentage of the Company s production coming from fields that have DD&A rates that are lower than the Company s recent historical composite DD&A rate (principally offshore fields and legacy onshore fields) and a corresponding increase in the percentage of the Company s production coming from fields that have DD&A rates that are higher than the Company s recent historical composite rate (principally production from the Latigo acquisition). The Company currently expects its average DD&A rate to increase from the 2006 rate over the remainder of 2007, as the effects of the higher rate per Mcf Latigo properties and the sale of the lower rate per Mcf Gulf of Mexico properties have a greater impact on the Company s overall production profile.

Production and Other Taxes

The decrease in production and other taxes during the second quarter of 2007, compared to the second quarter of 2006, relates primarily a decrease in Texas franchise tax obligations of $4.3 million, which was partially offset by an increase in production and ad valorem taxes of $1.7 million due to the Latigo acquisition, and an increase in ad valorem taxes of $1.0 million due to increasing property valuations. Production taxes for the six months ended June 30, 2007 increased from the same period in 2006 due to the Latigo acquisition, which contributed an additional $5.2 million in production and ad valorem taxes, and an increase in ad valorem taxes of $2.6 million due to increasing property valuations; these increases were offset by a $3.6 million reduction in franchise taxes.

Net Gain on Sales of Properties

During the three and six month periods ended June 30, 2007, the Company recognized gains on the sale of properties of $127.2 million and $129.5 million, respectively, which consisted primarily of a gain of approximately $224.9 million on the Gulf of Mexico sale and losses of approximately $7.8 million on the South Texas, Texas Gulf Coast and Louisiana Gulf Coast sales and approximately $89.4 million on the Texas Panhandle sale. During both the three and six months ended June 30, 2006, the Company recognized gains on the sale of properties of approximately $308.4 million related to the sale of 50% of the Company s working interest in its Gulf of Mexico properties.

Other

Other expense includes the Company s cost to move its products to market (transportation costs), accretion expense related to Company asset retirement obligations under generally accepted accounting principles, recognition of recoveries from business interruption insurance and various other operating expenses. The following table shows the significant items included in Other expense and the changes between periods (expressed in millions):

	For the Quarter Ended June 30,		**For the Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Transportation costs	$ 3.6	$ 2.9	7.0	$ 6.8
Business interruption insurance		(0.7)	(4.2)	(3.7)
Accretion expense	1.9	1.7	4.2	3.5
Hedge ineffectiveness	0.1	1.3	3.3	1.6
Other	2.4	0.6	2.8	2.4
Total	$ 8.0	$ 5.8	$ 13.1	$ 10.6

Interest

Interest Charges. The increase in the Company s interest charges for the second quarter of 2007, compared to the second quarter of 2006, resulted primarily from an increase the average amount of outstanding debt from $1.8 billion to $2.2 billion. The increase in interest charges for the six months ended June 30, 2007, compared to the same period in 2006, was due to an increase in the average amount of outstanding debt (primarily used to fund the Latigo acquisition) from $1.7 billion to $2.2 billion. See   Liquidity and Capital Resources   below.

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Capitalized Interest. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are substantially complete and ready for their intended use if projects are evaluated as successful. These include Northrock properties, which have been classified as discontinued operations. The increase in capitalized interest for the second quarter of 2007, compared to the same period in 2006, was primarily due to an increase in the weighted average dollar amount of oil and gas projects in progress subject to interest capitalization from $954.3 million to $1.1 billion. For the six months ended June 30, 2007, capitalized interest increased compared to the same period in 2006 primarily due to an increase in the weighted average dollar amount of oil and gas projects in progress subject to interest capitalization, which went from $961.8 million to $1.1 billion.

The Company changed the classification of interest capitalized in the Statement of Cash Flows from an operating cash outflow to an investing cash outflow in the fourth quarter of 2006. The Company elected not to change the classification of interest capitalized in the Statement of Cash Flows for periods prior to the fourth quarter of 2006 due to the immateriality of the amounts.

Commodity Derivative Expense

Commodity derivative expense for the three month and six month periods ended June 30, 2006 and 2007, respectively, represents both realized and unrealized gains and losses on derivative contracts that no longer qualify for hedge accounting treatment. Although the Company s collars are effective as economic hedges, the Company s Gulf of Mexico sales, along with the shut-in forecasted hydrocarbon production from the Company s Gulf of Mexico properties prior to the sales (resulting primarily from hurricane activity during the third quarter of 2005) caused certain of the gas and crude oil collar contracts to lose their qualification for hedge accounting under SFAS 133.

Income Tax Expense

Changes in the Company s income tax expense are a function of the Company s consolidated effective tax rate, the Company s pre-tax income (loss) and the jurisdiction in which the income (loss) is generated. The increase in the Company s income tax expense for the second quarter of 2007, compared to the second quarter of 2006, primarily resulted from a smaller reduction in the statutory federal income tax rates in Canada enacted in 2007 versus the reductions in 2006. In 2006, the Canadian federal rate was reduced from approximately 26% to 19% (phased in through 2010). In 2007 the tax rate in 2011 was further reduced from 19% to 18.5%. The Canadian tax rate reductions are reflected in the Company s continuing operations as required by GAAP, although all other Northrock tax items have been included in discontinued operations. The Company s consolidated effective tax rate was 29.1% for the second quarter of 2007, compared to 4.6% expense for the second quarter of 2006.

Liquidity and Capital Resources

The Company s primary needs for cash are for exploration, development, acquisition and production of oil and gas properties, repayment of principal and interest on outstanding debt and payment of income taxes. The Company funds its exploration and development activities primarily through internally generated cash flows and debt financing, and budgets capital expenditures based on projected cash flows. The Company adjusts capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition results, and cash flow. The Company has historically utilized net cash provided by operating activities, available cash, debt, and equity as capital resources to obtain necessary funding for all other cash needs. The following discussion includes cash flows from both continuing and discontinued operations.

The Company s cash flow provided by operating activities for the six months ended June 30, 2007 was $413.0 million, compared to cash flow provided by operating activities of $338.2 million for the six months ended June 30, 2006. Operating cash flows for the six months ended June 30, 2007 included a tax refund of $52 million for the overpayment of estimated taxes in the third quarter of 2006. Investing activities used cash flows of $714.3 during the first six months of 2006, primarily due to the Latigo acquisition, but generated cash flows of $64.8 during the first six months of 2007 due to an excess of funds provided by the Gulf of Mexico sale over capital expenditures. Cash flow from operating activities and debt financing were used during the first six months of 2007 to fund $511.0 million in cash expenditures (excluding capitalized interest) for capital and exploration projects and property acquisitions in the United States and Canada. During the six months ended June 30, 2007, the Company repaid senior debt obligations using cash of approximately $482.0 million (net of borrowings), primarily from the Company s sales of interests in the onshore Texas and Louisiana areas, the Texas Panhandle, and the Gulf of Mexico. In addition, the Company paid $8.8 million of common stock dividends. As of June 30, 2007, the Company had cash and cash equivalents of $20.3 million and long-term debt obligations of $1.8 billion (excluding debt discount) with no repayment obligations until 2009. The Company may determine to repurchase outstanding debt in the future, including in market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

Effective July 13, 2007, the Company s lenders redetermined the borrowing base under its bank credit facility at $1.3 billion. As of July 25, 2007, the Company had an outstanding balance of $375 million and a $1.0 billion borrowing capacity under the facility. As such, the available borrowing capacity under the facility was $625 million.

LIBOR Rate Advances

Under separate Promissory Note Agreements with various lenders, LIBOR rate advances are made available to the Company on an uncommitted basis up to $100 million. Advances drawn under these agreements are reflected as long-term debt on the Company s balance sheet because the Company currently has the ability and intent to refinance such amounts through borrowings under its bank credit facility, which is due in December 2009. The Company s 2011 Notes, 2013 Notes, 2015 Notes and 2017 Notes may restrict all or a portion of the amounts that may be borrowed under the Promissory Note Agreements. The Promissory Note Agreements permit either party to terminate the letter agreements at any time upon three business days notice. As of July 25, 2007, there were no advances outstanding under these agreements.

Property Sales

As part of the Company s strategic alternative initiative to enhance shareholder value, during the first six months of 2007 the Company sold properties in the onshore Texas and Louisiana areas and the Texas Panhandle for approximately $190.2 million. The Company also completed the sale of certain of its federal and state Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment for a purchase price of approximately $419.5 million. The Company used the proceeds from the sales to reduce outstanding debt.

On May 28, 2007, the Company entered into a definitive agreement to sell its wholly-owned subsidiary, Northrock Resources Ltd., for approximately $2 billion in cash. The sale is expected to close during the third quarter, and the Company currently plans to use the proceeds to pay off senior debt and invest the remainder while evaluating debt repayment strategies.

Future Capital and Other Expenditure Requirements

The Company s capital and exploration budget, which does not include any amounts that may be expended for acquisitions or any interest which may be capitalized resulting from projects in progress, was set at $720 million for 2007 ($470 million for continuing operations), of which approximately $437.5 million was spent to drill 183 wells in the United States and Canada during the six months ended June 30, 2007.

The Company currently anticipates that its available cash, cash provided by operating activities and property sales, and funds available under its bank credit facility will be sufficient to fund the Company s ongoing operating, interest and general and administrative expenses, capital expenditures, and dividend payments at current levels for the foreseeable future. The declaration and amount of future dividends on the Company s common stock will depend upon, among other things, the Company s future earnings and financial condition, liquidity and capital requirements, its ability to pay dividends and other payments under covenants contained in its debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

Insurance Recoveries

On February 28, 2007, the Company reached an agreement with its insurers to settle all outstanding claims related to Hurricanes Katrina and Rita. During the first six months of 2007, the Company recorded $4.2 million of business interruption insurance recoveries as a reduction of Other expenses and $18.6 million in property damage recoveries, of which $13.8 million was used to partially offset hurricane-related property damage repair costs recorded in Lease operating expense and $4.8 million was a reduction of a previously accrued insurance receivable.

Other Matters

Acquisition of the Company by Plains Exploration & Production Company

On July 17, 2007, PXP and the Company entered into a definitive agreement for PXP to acquire the Company in a stock and cash transaction valued at approximately $3.6 billion, based on PXP s closing price on July 16, 2007. Under the terms of the agreement, Pogo stockholders, on an aggregate basis, will receive 0.68201 shares of PXP common stock and $24.88 in cash for each share of the Company s common stock, which represents a total consideration of approximately $60 per share of the Company s common stock based on PXP s closing price on July 13, 2007. Total consideration for all of the issued and outstanding shares of the Company s common stock (excluding treasury shares) is 40 million PXP shares and approximately $1.5 billion in cash. The Company s stockholders have the right to elect to receive cash or stock, subject to proration. In addition, if the 10-day average trading price of PXP shares at the time of the merger varies from the closing price at July 13, 2007, certain adjustment provisions will apply. These adjustment provisions are intended to approximately equalize the then-market value of the PXP shares being issued and the amount of cash being paid to those stockholders who elect to receive all stock or all cash. The aggregate amount of cash being paid and the aggregate number of PXP shares being issued will not change, however. These adjustment provisions are set forth in the merger agreement and will be more fully described in the joint proxy statement/prospectus to be filed by the Company and PXP. The transaction is expected to qualify as a tax-free reorganization under Section 368(a).

This sale is expected to close during the fourth quarter of 2007, subject to customary closing conditions and regulatory approvals, including from the U.S. Securities and Exchange Commission, Federal Trade Commission and Department of Justice, and will be contingent upon approval by PXP stockholders of the issuance of shares of PXP stock to be used as merger consideration and adoption of the merger agreement by the Company s stockholders. The Boards of Directors of both companies have unanimously approved the merger agreement and each will recommend the transaction to their respective stockholders for approval. Once the transaction closes, it is anticipated that the PXP stockholders will own approximately 66% of the combined company and the Company s stockholders will own approximately 34% of the combined company.

Recent Accounting Pronouncements

On February 15, 2007, the Financial Accounting Standards Board (FASB) issued Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 (SFAS 159). The Statement permits entities to choose to measure eligible financial instruments and certain other items at fair market value, with the objective of improving financial reporting by giving entities the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The Statement is effective for fiscal years beginning after November 15, 2007. The adoption of SFAS 159 is not expected to have a material impact, if any, on the Company s financial statements.

ITEM 3. ***Quantitative and Qualitative Disclosures about Market Risk.***

The Company is exposed to market risk, including adverse changes in commodity prices, interest rates and foreign currency exchange rates as discussed below.

Commodity Price Risk

The Company produces and sells natural gas, crude oil, condensate and NGLs. As a result, the Company s financial results can be significantly affected as these commodity prices fluctuate widely in response to changing market forces. The Company makes use of a variety of derivative financial instruments only for non-trading purposes as a hedging strategy to manage commodity prices associated with oil and gas sales and to reduce the impact of commodity price fluctuations.

Current Hedging Activity

As of June 30, 2007 the Company held various derivative instruments. The Company has entered into natural gas and crude oil option agreements referred to as collars . Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company designated a significant portion of these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

The gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil derivative transactions are generally settled based on the average of the reported settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these contracts is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company s hedging activities as of June 30, 2007 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset/(Liability) (in millions)
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
July 2007 - December 2007	2,760	$ 6.00	$ 12.00	$ (0.3)
July 2007 - December 2007	920	$ 6.00	$ 12.15	$ (0.1)
July 2007 - December 2007	4,600	$ 6.00	$ 12.50	$ (0.4)
July 2007 - December 2007	460	$ 8.00	$ 13.40	$ 0.2
July 2007 - December 2007	1,380	$ 8.00	$ 13.50	$ 0.8
July 2007 - December 2007	460	$ 8.00	$ 13.52	$ 0.3
July 2007 - December 2007	460	$ 8.00	$ 13.65	$ 0.2
January 2008 - December 2008	1,830	$ 8.00	$ 12.05	$ 0.6
January 2008 - December 2008	2,745	$ 8.00	$ 12.10	$ 0.9
January 2008 - December 2008	915	$ 8.00	$ 12.25	$ 0.3
Crude Oil Contracts (Barrels)				
Collar Contracts:				
July 2007 - December 2007	736,000	$ 50.00	$ 75.00	$ (1.8)
July 2007 - December 2007	184,000	$ 50.00	$ 75.25	$ (0.4)
July 2007 - December 2007	1,104,000	$ 50.00	$ 77.50	$ (1.9)
July 2007 - December 2007	92,000	$ 60.00	$ 82.75	$
January 2008 - December 2008	183,000	$ 60.00	$ 80.00	$ (0.4)
January 2008 - December 2008	183,000	$ 60.00	$ 80.05	$ (0.4)
January 2008 - December 2008	183,000	$ 60.00	$ 80.10	$ (0.4)
January 2008 - December 2008	366,000	$ 60.00	$ 80.25	$ (0.8)

(a) MMBtu means million British Thermal Units

Although the Company s collars are effective as economic hedges, the Gulf of Mexico sales, along with the shut-in forecasted hydrocarbon production from the Company s Gulf of Mexico properties prior to the sales (resulting primarily from hurricane activity during the third quarter of 2005) caused certain of the gas and crude oil collar contracts to lose their qualification for hedge accounting under SFAS 133. The Company now recognizes changes in the fair value of these contracts in the consolidated statement of income for the period in which the change occurs under the caption Commodity derivative income (expense). As of June 30, 2007, the Company had the following open collar contracts that no longer qualify for hedge accounting:

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Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Liability (in millions)
Natural Gas Contracts (MMBtu)				
Collar Contracts:				
July 2007 - December 2007	3,680	$ 6.00	$ 12.15	$ (0.4)
July 2007 - December 2007	1,840	$ 6.00	$ 12.20	$ (0.2)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
July 2007 - December 2007	736,000	$ 50.00	$ 77.50	$ (1.3)
July 2007 - December 2007	276,000	$ 60.00	$ 83.00	$ (0.1)
July 2007 - December 2007	92,000	$ 60.00	$ 84.00	$

Interest Rate Risk

From time to time, the Company has entered into various financial instruments, such as interest rate swaps, to manage the impact of changes in interest rates. As of July 25, 2007, the Company has no open interest rate swap or interest rate lock agreements. Therefore, the Company s exposure to changes in interest rates primarily results from its short-term and long-term debt with both fixed and floating interest rates. The following table presents principal or notional amounts (stated in millions) and related average interest rates by year of maturity for the Company s debt obligations and their indicated fair market value at June 30, 2007:

	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0.0	$ 0.0	$ 390.0	$ 0.0	$ 0.0	$ 0.0	$ 390.0	$ 390.0
Average Interest Rate			6.60 %				6.60 %	
Fixed Rate	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 200.0	$ 1,250.0	$ 1,450.0	$ 1,454.6
Average Interest Rate					8.25 %	7.18 %	7.32 %	

Foreign Currency Exchange Rate Risk

The Company does not actively manage foreign currency risk in its foreign subsidiaries where the U.S. dollar is not the functional currency, primarily Canada, since the majority of transactions are denominated in the local currency. A substantial amount of the Company s cash is located in Canada, in Canadian dollars, which provides a natural hedge against foreign currency risk. Exposure from market rate fluctuations related to activities in New Zealand and Vietnam is not material at this time. As of July 25, 2007, the Company had no foreign currency financial derivatives.

ITEM 4. Controls and Procedures.

The Company has established disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to the officers who certify the Company s financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation as of the end of the period covered by this quarterly report, the Company s Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer have concluded that the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There were no changes in the Company s internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

ITEM 1A. Risk Factors.

In addition to the other information and the risk factors set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in the Company s Annual Report on Form 10-K for the year ended December 31, 2006.

Risks Related to the Company s Merger with PXP

Failure to complete the merger could negatively impact the stock price and the future business and financial results of the Company.

We cannot assure you that the merger agreement will be approved by the Company s stockholders, the issuance of the shares of PXP common stock will be approved by PXP stockholders or that the other conditions to the completion of the merger will be satisfied. In addition, both the Company and PXP have the right to terminate the merger agreement and pursue alternative transactions under certain conditions. If the merger is not completed, we will not receive any of the expected benefits of the merger and will be subject to risks and/or liabilities, including the following:

- failure to complete the merger might be followed by a decline in the market price of the Company s common stock,

- if the merger is terminated under specified circumstances and unless such termination is a result of a breach by PXP, the Company may be required to pay PXP a termination fee of $100 million,

- the Company is also obligated to reimburse PXP for up to $10 million of its expenses related to the merger if specified termination events occur,

- certain costs relating to the merger (such as legal, accounting and financial advisory fees) are payable by the Company whether or not the merger is completed, and

- the Company would continue to face the risks that it currently faces as an independent company.

If the merger is not completed, these risks and liabilities may materially adversely affect the Company s business, financial results, financial condition and stock price.

In addition, there can be no assurance that PXP will be successful in obtaining expected financing. Although financing is not a condition to closing of the merger, if PXP were not able to obtain the expected financing, or not able to obtain the financing on commercially reasonable terms, it might not be able to complete the merger.

Until the merger is completed or the merger agreement is terminated, under certain circumstances, the Company may not be able to enter into a merger or business combination with another party at a favorable price without incurring potentially significant expenses.

Unless and until the merger agreement is terminated, subject to specified exceptions (which are discussed in more detail in the merger agreement), the Company and it affiliates, advisors and representatives are restricted from initiating, soliciting or knowingly encouraging a proposal or offer for an alternative transaction with any person or entity other than PXP. Subject to specified conditions, including the requirement that the Company not be in material breach of these non-solicitation provisions, the Company s board may authorize a superior proposal (as defined in the merger agreement). However, in that event, the Company will be required to pay PXP a termination fee of $100 million plus up to an additional $10 million in respect of PXP s expenses. As a result of these restrictions, the Company may not be able to enter into an alternative transaction at a more favorable price without incurring potentially significant liability to PXP.

Uncertainties associated with the merger may cause the Company to lose employees, customers and business partners, and while the merger is pending, the Company is subject to restrictions on the conduct of its business.

The Company s current and prospective employees may be uncertain about their future roles and relationships with the Company following the completion of the merger. This uncertainty may adversely affect our ability to attract and retain key management and employees.

Our customers and business partners may not be as willing to continue business with us on the same or similar terms pending the completion of the merger, which would materially and adversely affect our business and results of operations. In addition, the merger agreement restricts us from taking specified actions without PXP s approval including, among other things, making certain significant acquisitions, dispositions or investments, making certain significant capital expenditures, and entering into certain material contracts. Our management may also be required to devote substantial time to merger-related activities, which could otherwise be devoted to pursuing other beneficial business opportunities.

Any delay in completing the merger and integrating the businesses may substantially reduce the benefits expected to be obtained from the merger.

In addition to obtaining the required regulatory clearances and approvals, the merger is subject to a number of other conditions beyond the control of the Company and PXP that may prevent, delay or otherwise materially adversely affect its completion. We cannot predict whether or when the conditions to closing will be satisfied. Any delay in completing the merger and integrating the businesses may diminish the benefits that we expect to achieve in the merger.

ITEM 4. Submission of Matters to Vote of Security Holders

The registrant held its annual meeting of stockholders in Houston, Texas on May 15, 2007. Each of the individuals nominated for election as a director was elected and the proposal before the meeting was approved. The following sets forth the items that were submitted to a vote of the stockholders and the results thereof:

(A) election of four directors, each for a term of three years. The vote tabulation for each nominee was as follows:

Nominee	For	Withheld
Paul G. Van Wagenen	54,145,939	717,770
Robert H. Campbell	54,158,753	704,456
Charles G. Groat	54,176,766	886,943
Daniel S. Loeb	54,145,939	717,770

(B) a proposal to ratify the appointment of PricewaterhouseCoopers LLP, independent accountants, to audit the financial statements of the Company for the year 2007, with 54,514,659 votes cast for ratification, 318,662 votes cast against ratification and 30,388 votes cast in absentia to the ratification.

ITEM 6. Exhibits

*3.1 Restated Certificate of Incorporation of Pogo Producing Company, as filed on April 28, 2004 (Exhibit 3.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File No. 1-7796).

*3.2 Bylaws of Pogo Producing Company, as amended and restated through July 16, 2002 (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-7792).

10.1 Share Purchase Agreement, dated as of May 28, 2007, by and among Pogo Alberta, ULC, Northrock Resources Ltd., Pogo Producing Company, 1325156 Alberta Ltd. and Abu Dhabi National Energy Company PJSC (a copy of any omitted schedule will be furnished supplementally to the SEC upon request).

*10.2 Agreement and Plan of Merger, dated July 17, 2007, by and among Pogo Producing Company, Plains Exploration & Production Company and PXP Acquisition LLC (Exhibit 2.1, Current Report on From 8-K filed on July 20, 2007).

31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.

32.2 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.

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* Asterisk indicates an exhibit incorporated by reference as shown.

Signatures

Pursuant to the requirements 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.

Pogo Producing Company

(Registrant)

/s/ James P. Ulm, II
James P. Ulm, II
Senior Vice President and Chief Financial Officer

/s/ Robert C. Marlowe
Robert C. Marlowe
Vice President Accounting

Date: July 30 , 2007