BERRY PETROLEUM CO
Form 10-Q
April 29, 2008

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 March 31, 2008
oTransition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __to ___
Commission file number 1-9735

BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

DELAWARE	77-0079387
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: (661) 616-3900

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, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filerx Accelerated filero Non-accelerated filero Smaller reporting companyo

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

As of April 15, 2008, the registrant had 42,664,779 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 1,797,784 shares of Class B Stock ($.01 par value) outstanding on April 15, 2008 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
FIRST QUARTER 2008 FORM 10-Q
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	March 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,679	$ 316
Short-term investments	58	58
Accounts receivable	117,235	117,038
Deferred income taxes	44,457	28,547
Fair value of derivatives	-	2,109
Assets held for sale	-	1,394
Prepaid expenses and other	10,814	11,557
Total current assets	175,243	161,019
Oil and gas properties (successful efforts basis), buildings and equipment, net	1,333,578	1,275,091
Other assets	15,308	15,996
	$ 1,524,129	$ 1,452,106
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 112,312	$ 90,354
Revenue and royalties payable	16,621	47,181
Accrued liabilities	26,068	21,653
Line of credit	10,200	14,300
Income taxes payable	2,952	2,591
Fair value of derivatives	130,338	95,290
Total current liabilities	298,491	271,369
Long-term liabilities:		
Deferred income taxes	134,694	128,824
Long-term debt	445,000	445,000
Abandonment obligation	36,310	36,426
Unearned revenue	227	398
Other long-term liabilities	5,111	1,657
Fair value of derivatives	143,216	108,458
	764,558	720,763
Shareholders' equity:		
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 42,663,779 shares issued and outstanding (42,583,002 in 2007)	426	425
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899) (1,797,784 in 2007)	18	18
Capital in excess of par value	70,967	66,590
Accumulated other comprehensive loss	(163,680)	(120,704)
Retained earnings	553,349	513,645
Total shareholders' equity	461,080	459,974

	$ 1,524,129	$ 1,452,106

The accompanying notes are an integral part of these financial statements.

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Month Periods Ended March 31, 2008 and 2007
(In Thousands, Except Per Share Data)

	Three months ended March 31, 2008	2007
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 164,495	$ 101,773
Sales of electricity	15,927	14,596
Gas marketing	3,231	-
Gain on sale of assets	415	-
Interest and other income, net	1,329	1,110
	185,397	117,479
EXPENSES		
Operating costs - oil and gas production	41,629	33,610
Operating costs - electricity generation	16,399	14,170
Production taxes	5,967	3,815
Depreciation, depletion & amortization - oil and gas production	27,076	18,725
Depreciation, depletion & amortization - electricity generation	693	762
Gas marketing	2,982	-
General and administrative	11,383	10,307
Interest	3,738	4,292
Commodity derivatives	708	-
Dry hole, abandonment, impairment and exploration	4,126	649
	114,701	86,330
Income before income taxes	70,696	31,149
Provision for income taxes	27,665	12,294
Net income	$ 43,031	$ 18,855
Basic net income per share	$ .97	$ .43
Diluted net income per share	$ .95	$ .42
Dividends per share	$ .075	$ .075
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	44,392	43,916
Effect of dilutive securities:		
Equity based compensation	795	603
Director deferred compensation	123	112

Weighted average number of shares of capital stock used to calculate diluted net income per share		45,310		44,631

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended March 31, 2008 and 2007
(In Thousands)

Net income	$	43,031	$	18,855
Unrealized gains (losses) on derivatives, net of income tax benefits of ($40,349) and ($7,885), respectively		(60,523)		(11,828)
Reclassification of realized gains (losses) on derivatives included in net income, net of income taxes (benefit) of $11,698 and ($361), respectively		17,547		(542)
Comprehensive income	$	55	$	6,485

The accompanying notes are an integral part of these financial statements.

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Three Month Periods Ended March 31, 2008 and 2007
(In Thousands)

	Three months ended March 31, 2008	2007
Cash flows from operating activities:		
Net income	$ 43,031	$ 18,855
Depreciation, depletion and amortization	27,769	19,487
Dry hole and impairment	2,728	187
Commodity derivatives	271	439
Stock-based compensation expense	2,107	1,792
Deferred income taxes	22,082	12,311
Gain on sale of oil and gas properties	(415)	-
Other, net	491	209
Change in book overdraft	4,609	(4,711)
Cash paid for abandonment	(971)	(255)
Increase in current assets other than cash and cash equivalents	(78)	(13,289)
Decrease in current liabilities other than book overdraft, line of credit and fair value of derivatives	(14,389)	(28,119)
Net cash provided by operating activities	87,235	6,906
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(75,869)	(73,472)
Property acquisitions	(261)	(1,088)
Additions to vehicles, drilling rigs and other fixed assets	(909)	(1,018)
Deposit on potential sale of asset	-	3,000
Proceeds from sale of assets	1,809	-
Capitalized interest	(4,485)	(3,998)
Net cash used in investing activities	(79,715)	(76,576)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	100,600	21,000
Payments on line of credit	(104,700)	(30,000)
Proceeds from issuance of long-term debt	69,200	90,000
Payments on long-term debt	(69,200)	(10,000)
Dividends paid	(3,327)	(3,295)
Proceeds from stock option exercises	1,388	1,148
Excess tax benefit and other	882	496
Net cash (used in) provided by financing activities	(5,157)	69,349
Net increase (decrease) in cash and cash equivalents	2,363	(321)
Cash and cash equivalents at beginning of year	316	416
Cash and cash equivalents at end of period	$ 2,679	$ 95

The accompanying notes are an integral part of these financial statements.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

1. General

All adjustments which are, in the opinion of management, necessary for a fair statement of Berry Petroleum Company's (the "Company") financial position at March 31, 2008 and December 31, 2007 and results of operations and cash flows for the three month periods ended March 31, 2008 and 2007 have been included. All such adjustments, except as described below, are of a normal recurring nature. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The accompanying unaudited condensed financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2007 financial statements. The December 31, 2007 Form 10-K/A should be read in conjunction herewith. The year-end condensed Balance Sheet was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America.

Our cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at March 31, 2008 and December 31, 2007 is $12.4 million and $7.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Certain reclassifications have been made to prior period financial statements to conform them to the current year presentation. Specifically, the change in book overdraft line in the Statements of Cash Flows is classified as an operating activity to reflect the use of these funds in operations, rather than their prior year classification as a financing activity.

In 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, this error has been corrected during the quarter ended March 31, 2008, with the effect of increasing our sales of oil and gas and accounts receivable by $10.5 million and $2.4 million, respectively, and reducing our royalties payable by $8.1 million.

In December 2007, we entered into a second long-term (ten year) firm transportation contract for our Colorado natural gas production. This contract is for 25,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. We have a total of 35,000 MMBtu/D contracted on the REX pipeline. We pay a demand charge for this capacity and our own production did not fill that capacity. In order to use as much of the transport as possible, we bought our partners' share of the gas produced in the Piceance at the market rate for that area. We then used our excess transport to move this gas to where it was eventually sold. The net of our gas marketing revenue and our gas marketing expense in the Statements of Income is $.2 million in the first quarter ended March 31, 2008. Our production will eventually reach our firm transportation capacity on this contract.

In the first quarter of 2008, we had two items in the dry hole, abandonment, impairment and exploration expense. Technical difficulties on three wells in the Piceance basin were encountered before reaching total depth and these holes were abandoned, for approximately $2.7 million in cost, in favor of drilling to the same bottom hole location by drilling a new well. In addition, we had $1.4 million of exploration expense in the DJ basin.

In the first quarter of 2008, we renegotiated a price-sensitive royalty that burdens certain of our properties resulting in an increase to net income of $1.4 million in the first quarter of 2008. We completed negotiations and are finalizing this amendment which will be a permanent reduction assuming we attain a minimum steam injection level.

We have decided we will not proceed with our previously announced plans to organize a master limited partnership (MLP) due to the unfavorable capital market conditions. We expensed $.6 million of legal and accounting fees related to the formation of the MLP.

Proceeds from the sale of our Prairie Star assets are $1.8 million in the Statements of Cash Flows and the gain from that sale is $.4 million in the Statements of Income in the first quarter ended March 31, 2008.

2. Recent Accounting Developments

In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements. SFAS 160 was issued to establish accounting and reporting standards for the noncontrolling interest in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. We do not expect the adoption of SFAS 160 to have a material effect on our financial statements and related disclosures. The effective date of this Statement is the same as that of the related Statement 141(R).

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

2. Recent Accounting Developments (Cont'd)

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which expands the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement will require the additional disclosures described above.

3. Fair Value Measurement

In September 2006, SFAS No. 157, Fair Value Measurements was issued by the FASB. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. We adopted this Statement at January 1, 2008.

Determination of fair value
We have an established and well-documented process for determining fair values. Fair value is based upon quoted market prices, where available. To ensure that the valuations are appropriate, we have various controls in place. These include: identification of the inputs to the fair value methodology through review of counterparty statements and other supporting documentation, and determination of the validity of the source of the inputs, corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Valuation hierarchy
SFAS 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.
• Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

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

Our oil swaps, natural gas swaps and interest rate swaps are valued using the counterparties’ marked-to-market statements which are validated by our internally developed models and are classified within Level 2 of the valuation hierarchy. Derivatives that are valued based upon models with significant unobservable market inputs and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

3. Fair Value Measurement (Cont'd)

Assets and liabilities measured at fair value on a recurring basis

March 31, 2008 (in millions)	Total carrying value on the condensed Balance Sheet	Level 2	Level 3
Commodity derivatives	$ 265.0	$ 21.1	$ 243.9
Interest rate swaps	8.5	8.5	-
Total liabilities at fair value	$ 273.5	$ 29.6	$ 243.9

Changes in Level 3 fair value measurements
The table below includes a rollforward of the Balance Sheet amounts for the first quarter of 2008 (including the change in fair value) for financial instruments classified by us within Level 3 of the valuation hierarchy. When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

Three months ended March 31, 2008 (in millions)

Fair value, January 1, 2008	$ 194.3
Total realized and unrealized gains and (losses) included in Sales of oil and gas	75.6
Purchases, sales and settlements, net	(25.9)
Transfers in and/or out of Level 3	-
Fair value, March 31, 2008	$ 243.9
Total unrealized gains and (losses) included in income related to financial assets and liabilities still on the condensed Balance Sheet at March 31, 2008	$ -

In February of 2007, the FASB issued SFAS 159, which is effective for fiscal years beginning after November 15, 2007. SFAS 159 provides an option to elect fair value as an alternative measurement for selected financial assets and financial liabilities not previously carried at fair value. We adopted this statement at January 1, 2008, but did not elect fair value as an alternative, as provided in the Statement.

4. Hedging

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At March 31, 2008, our net fair value of derivatives liability was $273.6 million as compared to $201.6 million at December 31, 2007 which reflects increases in commodity prices in the period. Based on NYMEX strip pricing as of March 31, 2008, we expect to make hedge payments under the existing derivatives of $128.8 million during the next twelve months. At March 31, 2008, Accumulated Other Comprehensive Loss consisted of $163.7 million, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at March 31, 2008. Deferred net losses recorded in Accumulated Other Comprehensive Loss at March 31, 2008 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.

We entered into the following natural gas hedges during the three months ended March 31, 2008:

- Swaps on 15,400 MMBtu/D at $8.50 for the full year of 2009 and basis swaps on the same volumes for average prices of $1.17, $1.12, $.97, and $1.05 for each of the four quarters of 2009, respectively.

These hedges have been designated as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. These swaps were not highly effective at inception, so we subsequently entered into basis swaps and established effectiveness at that time. In 2007, we also entered into natural gas swap contracts that were not highly effective. Thus, we recognized an unrealized net loss of approximately $.7 million on the income statement under the caption “Commodity derivatives” for the three months ended March 31, 2008.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

5. Asset Retirement Obligations

Inherent in the fair value calculation of the asset retirement obligation (ARO) are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

Under SFAS 143, the following table summarizes the change in abandonment obligation for the three months ended March 31, 2008 (in thousands):

Beginning balance at January 1	$ 36,426
Liabilities settled	(971)
Accretion expense	855
Ending balance at March 31	$ 36,310

6. Income Taxes

The effective tax rate was 39% for the first quarter of 2008 compared to 37% for the fourth quarter of 2007 and 39% for the first quarter of 2007. Our rate differs from the combined federal and state statutory tax rate (net of the federal benefit), primarily due to certain business incentives.

As of March 31, 2008, we had a gross liability for uncertain tax benefits of $13 million of which $10.6 million, if recognized, would affect the effective tax rate. There were no significant changes to the calculation since year end 2007.

Due to the uncertainty about the periods in which examinations will be completed and limited information related to current audits, we are not able to make reasonably reliable estimates of the periods in which cash settlements will occur with taxing authorities for the noncurrent liabilities.

7. Long-term and Short-term Debt Obligations

Short-term debt
In 2005, we completed an unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either us or the lender. At March 31, 2008 the outstanding balance under this Line of Credit was $10.2 million. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1%. The weighted average interest rate on outstanding borrowings on the Line of Credit at March 31, 2008 was 3.7%.

Long-term debt
In 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Notes). The deferred costs of approximately $5 million associated with the issuance of this debt are being amortized over the ten year life of the Notes.

We have a senior unsecured bank credit facility agreement (the Agreement) with a banking syndicate through June 30, 2011. The Agreement is a revolving credit facility for up to $750 million. In 2007, we increased our borrowing base to $550 million and in the second quarter of 2008, we increased our annual borrowing base to $650 million with a funding commitment from our banking syndicate to $600 million. The outstanding Line of Credit reduces our borrowing capacity available under the Agreement.

The total outstanding debt at March 31, 2008 under the credit facility and the short-term Line of Credit was $245 million and $10.2 million, respectively, leaving $295 million in borrowing capacity available. Interest on amounts borrowed under this debt is charged at LIBOR plus a margin of 1.00% to 1.75% or the prime rate, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. We are required under the Agreement to pay an annual commitment fee of .25% to .375% on the unused portion of the credit facility.

The maximum amount available is subject to an annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both we and the banks have bilateral rights to one additional redetermination each year.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

7. Long-term and Short-term Debt Obligations (Cont'd)

The Agreement contains restrictive covenants which, among other things, require us to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The $200 million Notes are subordinated to our credit facility indebtedness. As long as the interest coverage ratio (as defined) is met, we may incur additional debt. We were in compliance with all covenants as of March 31, 2008. The weighted average interest rate on total outstanding borrowings at March 31, 2008 was 5.7%.

Additionally, in 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility for five years. These interest rate swaps have been designated as cash flow hedges.

8. Contingencies and Commitments

We have no accrued environmental liabilities for our sites, including sites in which governmental agencies have designated us as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. We are involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of our business. In the opinion of management, the resolution of these matters will not have a material effect on our financial position, or on the results of operations or liquidity.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner will increase its total purchased volumes to 5,000 Bbl/D beginning June 29, 2008 through June 2013, as provided in our contract. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI.

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

General. The following discussion provides information on the results of operations for the three month periods ended March 31, 2008 and 2007 and our financial condition, liquidity and capital resources as of March 31, 2008. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of development, exploitation, acquisition, exploration and hedging activities. The realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by world supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. The cost of natural gas used in our steaming operations and electrical generation, production rates, labor, equipment costs, maintenance expenses, and production taxes are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

Overview. We seek to increase shareholder value through consistent growth in our production and reserves, both through the drill bit and acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

- Developing our existing resource base
- Acquiring additional assets with significant growth potential
- Utilizing joint ventures with respected partners to enter new basins
- Accumulating significant acreage positions near our producing operations
- Investing our capital in a disciplined manner and maintaining a strong financial position

Notable First Quarter Items.

- Production averaged 28,066 BOE/D, up 10% from the first quarter of 2007
- Renegotiated an ongoing royalty which resulted in an increase to net income of $1.4 million in the first quarter of 2008
- Production at Poso Creek averaged 2,700 Bbl/D, up 13% from the fourth quarter of 2007
- Increased Piceance net average production to 16.8 MMcf/D, up 15% from the fourth quarter 2007
- Corrected our calculation of certain royalties payable over the last three years which resulted in a one time cumulative increase to net income of $6.4 million in the first quarter of 2008
- Announced headquarters relocation in 2008 to Denver, Colorado

Notable Items and Expectations for the Second Quarter of 2008.

- Targeting a production average above 29,000 BOE/D and an exit rate of 30,000 BOE/D in the second quarter of 2008
- Drilling wells, increasing steam generation capacity and adding supporting infrastructure to increase production at diatomite
- Received an upgrade of our corporate credit rating to "BB" and senior subordinated note rating to "B+" by Standard & Poor's Rating Service
- Moody's Investors Services placed our corporate rating and senior subordinated note rating under review for possible upgrade
- Increased our credit facility annual borrowing base to $650 million from $550 million

Overview of the First Quarter of 2008. We had net income of $43 million, or $.95 per diluted share and net cash from operations was $87 million. We drilled 145 gross wells and capital expenditures, excluding property acquisitions, totaled $77 million. We experienced no increase in debt in the first quarter of 2008 compared to the fourth quarter of 2007. We achieved average production of 28,066 BOE/D in the first quarter of 2008, up .2% from an average of 28,023 BOE/D in the fourth quarter of 2007. Our 2008 $295 million capital program is designed to achieve at least a 10% increase in production and a 10% increase in reserves at a very competitive finding and development cost while being funded entirely out of internally generated cash flow from operations. We renegotiated a price-sensitive royalty that burdens certain of our production resulting in an increase to net income of $1.4 million in the first quarter of 2008. We completed negotiations and are finalizing this amendment which will be a permanent reduction assuming we attain a minimum steam injection level. We expect that our royalty burden will be reduced by approximately $10 million in 2008 based on current prices and our production plans.

Results of Operations. The following companywide results are in millions (except per share data) for the three months ended:

	March 31, 2008 (1Q08)	March 31, 2007 (1Q07)	1Q08 to 1Q07 Change	December 31, 2007 (4Q07)	1Q08 to 4Q07 Change
Sales of oil	$ 131	$ 81	62%	$ 109	20%
Sales of gas	33	21	57%	24	38%
Total sales of oil and gas	$ 164	$ 102	61%	$ 133	23%
Sales of electricity	16	15	7%	15	7%
Other revenues	5	1	400%	5	-%
Total revenues and other income	$ 185	$ 118	57%	$ 153	21%
Net income	$ 43	$ 19	126%	$ 32	34%
Earnings per share (diluted)	$ .95	$ .42	126%	$ .71	34%

Global and California crude oil demand continues to remain strong although pricing is volatile. Product prices continued to exhibit an overall-strengthening trend in 2008. Oil is a globally priced commodity and is priced according to the supply and demand of crude oil and its products. Other dominant factors in the pricing of our crude oil include the condition of the global economy and political tension in or near oil producing regions. We expect that crude prices will continue to be volatile in 2008.

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Crude oil sales in the three months ended March 31, 2008 were 20% higher than the three months ended December 31, 2007 resulting from price increases of 21% and sales volume increases of 2%. Gas sales in the three months ended March 31, 2008 were 38% higher than the three months ended December 31, 2007 resulting from production increases of 2% and a price increase of 36%. Management estimates that for 2008, a $1.00 per MMBtu change in NYMEX Henry Hub natural gas prices would result in a $3 million change in annual net income, demonstrating our relative insensitivity to natural gas prices companywide.

In 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, this error has been corrected during the quarter ended March 31, 2008, with the effect of increasing our sales of oil and gas and accounts receivable by $10.5 million and $2.4 million, respectively, and reducing our royalties payable by $8.1 million.

Operating data. The following table is for the three months ended:

		March 31, 2008	%		March 31, 2007	%		December 31, 2007	%
Heavy Oil Production (Bbl/D)		16,375	58		16,140	63		16,595	59
Light Oil Production (Bbl/D)		3,510	13		3,233	13		3,395	12
Total Oil Production (Bbl/D)		19,885	71		19,373	76		19,990	71
Natural Gas Production (Mcf/D)		49,086	29		36,704	24		48,196	29
Total (BOE/D)		28,066	100		25,490	100		28,023	100
Oil and gas, per BOE:									
Average sales price before hedging	$	71.67		$	43.62		$	60.38	
Average sales price after hedging		60.43			43.84			52.32	
Oil, per Bbl:									
Average WTI price	$	97.82		$	58.23		$	90.50	
Price sensitive royalties		(4.47)			(3.74)			(6.68)	
Quality differential and other		(10.78)			(8.78)			(9.92)	
Crude oil hedges		(15.60)			.03			(13.57)	
Correction to royalties payable		5.85			-			-	
Average oil sales price after hedging	$	72.82		$	45.74		$	60.33	
Natural gas price:									
Average Henry Hub price per MMBtu	$	8.74		$	7.18		$	7.39	
Conversion to Mcf		.42			.34			.35	
Natural gas hedges		(.12)			.13			.91	
Location, quality differentials and other		(1.61)			(1.37)			(3.21)	
Average gas sales price after hedging	$	7.43		$	6.28		$	5.44	

Gas Basis Differential. Natural gas prices in the Rockies have stabilized since the start of interim service on the REX pipeline in January 2008. The basis differential between Henry Hub (HH) and Colorado Interstate Gas (CIG) index has narrowed, as anticipated, due to the increased take away capacity added by the REX pipeline. We have contracted a total of 35,000 MMBtu/D on this pipeline under two separate transactions to provide firm transport for our Piceance basin gas production. In the first quarter of 2008, the CIG basis differential per MMBtu, based upon first-of-month values, averaged $1.07 below HH and ranged from $.91 to $1.19 below HH. Although related to CIG, the actual basin price varies. Gas from the Piceance basin traded slightly below the CIG price while Uinta basin gas sold for approximately $.15 below CIG pricing. After the REX startup in 2008, all of the Piceance basin gas was sold at mid-continent (ANR and NGPL) indexes which averaged approximately $.17 above the CIG index pricing before the cost of transportation was included.

DJ Basin gas is priced using one of two indices. Approximately two-thirds of our volume from our DJ natural gas properties is tied to the Panhandle Eastern Pipeline (PEPL) index for pricing and the remaining volume to CIG pricing. For that portion of the production with firm transportation on either the Cheyenne Plains Pipeline or the KMIGT pipeline, pricing is based upon the PEPL index which averaged approximately $.85 below the HH index before the cost of transportation is considered. The remainder of the DJ Basin gas is sold slightly above the CIG index price.

Gas Marketing. In December 2007, we entered into a second long-term (ten year) firm transportation contract for our Colorado natural gas production. This contract is for 25,000 MMBtu/D on the REX pipeline for gas production in the Piceance basin. We pay a demand charge for this capacity and our own production did not fill that capacity. In order to maximize our firm transportation capacity, we bought our partners' share of the gas produced in the Piceance at the market rate for that area. We then used our excess transport to move this gas to where it was eventually sold. The net of our gas marketing revenue and our gas marketing expense in the Statements of Income is $.2 million in the first quarter ended March 31, 2008. Eventually our own production will reach and exceed our firm transportation capacity on this contract.

Oil Contracts. Utah - During 2007, our Utah light crude oil was sold under multiple contracts with different purchasers for varying pricing terms, and in some cases our realized price was further reduced by transportation charges. As operator we deliver all produced volumes pursuant to these contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Our Utah crude oil is a paraffinic crude and can be processed efficiently by only a limited number of refineries within the region. Increased production of crude oil in the region, the ability of refiners to process other higher sulfur crudes as a result of capital upgrades, as well as the increasing availability of Canadian crude oil, put downward pressure on the sales price of our crude oil.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner will increase its total purchased volumes to 5,000 Bbl/D beginning June 29, 2008 through June 2013, as provided in our contract. Gross oil production averaged approximately 4,200 BOE/D in the quarter ended March 31, 2008 and we are evaluating options on a quarterly basis to meet the contractual volume. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. As global and regional prices of crude oil increased since we entered into this contract, we are receiving crude oil prices below the posted price, although this posted price is thinly traded and does not necessarily indicate the actual price at which a seller can market their crude oil. While our price differentials have widened as the crude oil price increased, we are able to sell 100% of our crude oil.

Hedging. See Note 4 to the unaudited condensed financial statements and Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Electricity. We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the cost-effective production of heavy oil in California. We sell our electricity to utilities under standard offer contracts based on "avoided cost" or SRAC pricing approved by the California Public Utilities Commission (CPUC) and under which our revenues are currently linked to the cost of natural gas. Natural gas index prices are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to manage our cost of producing steam more effectively.

In 2007, our electricity operations improved partially from the lower cost of our firm transportation natural gas we purchased. We purchase and transport 12,000 average MMBtu/D on the Kern River Pipeline under our firm transportation contract and use this gas to produce conventional and cogeneration steam in the Midway-Sunset field. The differential between Rocky Mountain gas prices and Southern California Border prices increased during 2007 allowing us to purchase a portion of our gas at prices less than the Southern California Border price. As our electricity revenue is linked to Southern California Border prices, the fuel we purchased at lower Rocky Mountain prices was the primary contributor to the increase in our electricity margin in 2007. We purchased approximately 38 MMBtu/D as fuel for use in our cogeneration facilities in the year ended December 31, 2007. Rockies natural gas differentials have stabilized near their historical levels and we do not expect to have significant positive electricity margins in 2008. We expect to have small gains or losses on electricity on a quarterly basis which depends on seasonality as we receive improved pricing during the summer months. On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes prospectively the way SRAC energy prices will be determined for existing and new Standard Offer (SO) contracts and revises the capacity prices paid under current SO1 contracts. Based on our preliminary analysis, we do not believe that the proposed pricing changes will materially affect us in 2008.

The following table is for the three months ended:

	March 31, 2008	March 31, 2007	December 31, 2007
Electricity			
Revenues (in millions)	$ 15.9	$ 14.6	$ 14.9
Operating costs (in millions)	$ 16.4	$ 14.2	$ 11.0
Electric power produced - MWh/D	2,152	2,117	2,099
Electric power sold - MWh/D	1,959	1,914	2,077
Average sales price/MWh	$ 90.48	$ 81.08	$ 78.98
Fuel gas cost/MMBtu (including transportation)	$ 7.94	$ 6.70	$ 6.10

Oil and Gas Operating, Production Taxes, G&A and Interest Expenses. The following table presents information about our operating expenses for each of the three month periods ended:

	Amount per BOE			Amount (in thousands)		
	March 31, 2008	March 31, 2007	December 31, 2007	March 31, 2008	March 31, 2007	December 31, 2007
Operating costs – oil and gas production	$ 16.30	$ 14.65	$ 14.70	$ 41,629	$ 33,610	$ 37,889
Production taxes	2.34	1.66	1.91	5,967	3,815	4,918
DD&A – oil and gas production	10.60	8.16	10.94	27,076	18,725	28,212

G&A		4.46		4.49		4.24		11,383		10,307	10,918
Interest expense		1.46		1.69		1.43		3,738		4,292	3,693
Total	$	35.16	$	30.65	$	33.22	$	89,793	$	70,749	$ 85,630

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the three months ended March 31, 2008, stated on a unit-of-production basis, increased 15% over the three months ended March 31, 2007 and increased 6% as compared to the three months ended December 31, 2007. The changes were primarily related to the following items:

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- Operating costs: The majority of the increase in our operating costs was due to higher steam costs resulting from higher fuel costs. The following table presents steam information:

	March 31, 2008 (1Q08)	March 31, 2007 (1Q07)	1Q08 to 1Q07 Change	December 31, 2007 (4Q07)	1Q08 to 4Q07 Change
Average volume of steam injected (Bbl/D)	91,326	86,132	6%	90,894	1%
Fuel gas cost/MMBtu (including transportation)	$ 7.94	$ 6.70	19%	$ 6.10	30%

As we remain in a strong commodity price environment, we anticipate that cost pressures within our industry may continue due to greater field activity and rising service costs in general. Based on current plans, we are targeting average steam injection in 2008 of approximately 110,000 BSPD or a 25% increase compared to 2007.

- Production taxes: Our production taxes have increased compared to the first and the fourth quarters of 2007 as commodity prices and thus the values of our oil and natural gas has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track oil and gas prices generally.

- Depreciation, depletion and amortization: DD&A increased per BOE by 30% in the first three months of 2008 as compared to the first three months of 2007 due to an increase in capital spending in fields with higher drilling and leasehold acquisition costs, which is in line with our expectations. DD&A per BOE was similar to the fourth quarter of 2007 as our capital expenditures have remained consistent.

- General and administrative: Approximately 70% of our G&A is related to compensation. The primary reasons for the increase in G&A during the first quarter of 2008 was recording to expense $.6 million of previously capitalized legal and accounting fees related to the formation of an MLP.

- Interest expense: Our total outstanding borrowings were approximately $455 million at March 31, 2008 compared to $477 million and $459 million at March 31, 2007 and December 31, 2007, respectively. For the three months ended March 31, 2008, $4.5 million of interest cost has been capitalized and we expect to capitalize approximately $20 million of interest cost during the full year of 2008.

Estimated 2008 Oil and Gas Operating, G&A and Interest Expenses. We estimate our average 2008 production volume will range between 29,500 BOE/D and 30,500 BOE/D. Based on actual first quarter and the remainder of 2008 at NYMEX WTI crude oil price of $100 per barrel and NYMEX HH natural gas price of $10.00 per MMBtu, we expect our expenses to be within the following ranges:

		Anticipated range in 2008 per BOE
Operating costs-oil and gas production (1)	$	17.75 to 19.00
Production taxes		2.20 to 2.70
DD&A – oil and gas production		10.00 to 11.00
G&A		4.00 to 4.50

Interest expense		1.10 to 1.40
Total	$	35.05 to 38.60

(1) We expect operating costs to increase in 2008 as compared to 2007 due to higher projected natural gas costs.

Income Taxes. We experienced an effective tax rate in the three months ended March 31, 2008 of 39%, which is in line with our projections. Our rate differs from the combined federal and state statutory tax rate (net of the federal benefit), primarily due to certain business incentives. See Note 6 to the unaudited condensed financial statements.

Development, Exploitation and Exploration Activity. We drilled 145 gross (128 net) wells during the first quarter of 2008. As of March 31, 2008, we have four rigs drilling on our properties under long-term contracts and six more under short term contracts.

Drilling Activity. The following table sets forth certain information regarding drilling activities (including operated and non-operated wells):

	Three months ended March 31, 2008	
	Gross Wells	Net Wells
S. Midway	23	23
N. Midway	36	36
S. Cal	21	21
Piceance	19	9
Uinta	9	9
DJ	37	30
Totals	145	128

Properties
We have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Southern California including Poso Creek and Placerita (S. Cal), Piceance, Uinta and DJ.

S. Midway – During the three months ended March 31, 2008, production averaged approximately 9,200 Bbl/D compared to approximately 9,500 Bbl/D and 9,100 Bbl/D during the three month periods ended March 31, 2007 and December 31, 2007, respectively. We will invest $31 million on our S. Midway properties in 2008 to drill additional deeper horizontal wells along the cold, unswept flanks of the reservoir. Additional vertical wells will also be drilled to provide steam support for these horizontal wells. The first seven of the horizontal wells plus the vertical steam support wells have been drilled and are performing as expected. We plan to drill the remaining locations during the second quarter of 2008. We will also be developing the Monarch reservoir on our legacy Ethel D property. In 2008, we plan on drilling 33 wells including a four pattern steam flood pilot project at Ethel D. During the first quarter we drilled and completed six of these wells and these wells are currently being steamed. We are currently in the process of drilling the remaining 27 wells.

N. Midway – During the three months ended March 31, 2008, production from the area averaged approximately 2,400 Bbl/D compared to approximately 1,600 Bbl/D and 2,400 Bbl/D during the three month periods ended March 31, 2007 and December 31, 2007, respectively. In October 2007, we embarked on a full-scale, continuous development program of the Diatomite and we expect to drill non-stop over the next four years. Over 70 new producers have been drilled since October 2007. We have just recently started to bring these wells on line as the necessary infrastructure was installed to adequately steam and produce these wells. We will nearly triple our producing well count this year from 80 wells at the end of 2007 to approximately 240 wells by year end 2008. Steam injection necessary to support our development will also increase dramatically. Our steam generation capacity, which stood at approximately 10,000 BSPD at the end of 2007, will increase by 150% to 25,000 BSPD by the end of 2008. The additional wells, steam and supporting infrastructure should enable us to increase production which averaged 1,400 BOE/D during the first quarter of 2008 to over 3,000 BOE/D by year end 2008.

S. Cal – During the three months ended March 31, 2008, production averaged approximately 4,800 Bbl/D compared to approximately 4,800 Bbl/D and 4,700 Bbl/D during the three month periods ended March 31, 2007 and December 31, 2007, respectively. This year's plans at Poso Creek call for further expansion including the addition of a fourth steam generator, which we brought on line in February, drilling 28 producers and expanding the steam flood. As of April 2008, 26 of the 28 planned producers have been drilled and production has continued to increase and is currently up to 3,200 BOE/D. The remaining producers and steam flood pattern injectors will be drilled over the second quarter of 2008 and should help further improve our production.

Piceance – During the first quarter of 2008, production from the Piceance averaged 16.8 MMcf/D, an increase of 15% over the fourth quarter of 2007. Of the Berry operated wells, we drilled 15 gross wells (9 net) during the first quarter of 2008. We are currently drilling our 20th well of the year and the 90th well since we acquired our original Piceance basin acreage in early 2006. We continue to operate four drilling rigs while we continue to see further efficiencies with repeated drilling durations of 14 to 16 days for a mesa well. We expect significant gains over the next quarter as we move into the prime summer completion season. The production of the wells is as expected with the 30 day initial production rates slightly above our target of 1.2 MMcf/D. In the first quarter of 2008, technical difficulties on three wells were encountered before reaching total depth and these holes were abandoned, for approximately $2.7 million in cost, in favor of drilling to the same bottom hole location by drilling a new well.

Over the last two years we have re-engineered our mesa drilling operations. We have made significant investments constructing the needed infrastructure to support our operations, and we now are realizing improved economic returns as our manufacturing

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process developing this long term asset continues to improve. Additionally, those returns are substantially enhanced due to the strong natural gas market and our ability to transport our gas on the recently opened REX pipeline.

Uinta – Average daily production during the first quarter from all Uinta basin assets was approximately 5,700 net BOE/D. We continue to have one drilling rig operating in the basin. The development at Brundage Canyon continues to be focused on drilling the high graded areas in the core of the field where we have drilled nine wells in the first quarter of 2008 and increased our Uinta production to an exit rate of over 6,000 BOE/D. Evaluating the waterflood feasibility at Brundage Canyon has progressed with the selection a final pilot waterflood pattern and we have begun the permitting process, with first injection expected by year end 2008. Starting in the second quarter we anticipate further delineating the Ashley Forest with drilling six to ten wells under our current environmental approvals and we will continue to optimize and pace our Uinta drilling program while the Ashley Forest Development EIS progresses towards its anticipated approval in early 2009.

DJ – During the first quarter of 2008, we drilled 37 successful gross Niobrara development wells in Yuma County, Colorado, with a 100% success rate. Average daily production in the DJ for the first quarter of 2008 was 18.9 net MMcf/D and we had $1.4 million of exploration expense in the first quarter. Currently we are interpreting an additional 75 square miles of 3-D seismic that we acquired over the winter and anticipate this will continue to replenish and add to our sizeable inventory of low risk development locations and allow many more years of drilling.

Financial Condition, Liquidity and Capital Resources. Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices, production rates and operating expenses have been the primary reason for changes in our cash flow from operating activities. We have a senior unsecured revolving bank credit facility agreement (the Agreement) with a banking syndicate through June 30, 2011. The Agreement is a revolving credit facility for up to $750 million. In 2007, we increased our borrowing base to $550 million and in the second quarter of 2008, we increased our annual borrowing base to $650 million with a funding commitment from our banking syndicate to $600 million. In October 2006, we completed the sale of $200 million of ten year 8.25% senior subordinated notes.

As of March 31, 2008, we had total borrowings under the Agreement and Line of Credit of $255.2 million and $200 million under our senior subordinated ten year notes.

Capital Expenditures. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Acquisitions are typically debt financed. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

In 2008, we have a capital program of approximately $295 million, excluding acquisitions. The capital development program may be revised due to realized commodity prices and price expectations, equipment availability, permitting and/or changes in our internal development plans. Our 2008 expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2008, we plan to invest approximately $118 million, or 40%, in our heavy crude oil assets, and $175 million, or 59%, in our natural gas and light oil assets. Capital expenditures, excluding property acquisitions, totaled $77 million during the three months ended March 31, 2008.

Working Capital and Cash Flows. Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs. Crude oil and gas sales in the three months ended March 31, 2008 were 23% higher than the three months ended December 31, 2007 resulting from a 21% increase in oil prices (see graphs on page 12) and a 36% increase in gas prices (see graphs on page 12) and production increases in natural gas, partially offset by production declines in oil. Proceeds from the sale of our Prairie Star assets are $1.8 million in the Statements of Cash Flows and the gain from that sale is $.4 million in the Statements of Income in the first quarter ended March 31, 2008.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We use our long-term borrowings under our credit facility primarily to fund property acquisitions. Generally, we use excess cash to pay down borrowings under our credit arrangement. As a result, we often have a working capital deficit or a relatively small amount of positive working capital.

The table below compares financial condition, liquidity and capital resources changes for the three month periods ended (in millions, except for production and average prices):

	March 31, 2008 (1Q08)	March 31, 2007 (1Q07)	1Q08 to 1Q07 Change	December 31, 2007 (4Q07)	1Q08 to 4Q07 Change
Average production (BOE/D)	28,066	25,490	10%	28,023	-%
Average oil and gas sales prices, per BOE after hedging	$ 60.43	$ 43.84	38%	$ 52.32	16%
Net cash provided by operating activities (1)	$ 87	$ 7	1,143%	$ 57	53%
Working capital	$ (123)	$ (72)	(71%)	$ (110)	(12%)
Sales of oil and gas	$ 164	$ 102	61%	$ 133	23%
Total debt	$ 455	$477	(5%)	$ 459	(1%)
Capital expenditures, including acquisitions and deposits on acquisitions	$ 77	$ 76	1%	$ 76	1%
Dividends paid	$ 3.3	$ 3.3	-%	$ 3.3	-%

(1) The change in book overdraft line in the Statements of Cash Flows is classified as an operating activity to reflect the use of these funds in operations, rather than their prior year classification as a financing activity.

Contractual Obligations. Our contractual obligations as of March 31, 2008 are as follows (in millions):

	Total	2008	2009	2010	2011	2012	Thereafter
Total debt and interest	$ 629.8	$ 29.8	$ 25.7	$ 25.7	$ 266.1	$ 16.5	$ 266.0
Abandonment obligations	36.3	1.1	1.4	1.4	1.5	1.5	29.4
Operating lease obligations	17.6	1.8	2.2	2.1	2.1	2.1	7.3
Drilling and rig obligations	69.0	20.5	18.8	8.1	21.6	-	-
Firm natural gas transportation contracts	169.4	11.4	19.5	19.5	19.5	19.1	80.4
Total	$ 922.1	$ 64.6	$ 67.6	$ 56.8	$ 310.8	$ 39.2	$ 383.1

Drilling obligations - Under our June 2006 joint venture agreement in the Piceance basin we are required to have 120 wells drilled by February 2011 to avoid penalties of $.2 million per well or a maximum of $24 million. As of March 31, 2008 we have drilled 15 of these wells.

Other Obligations.
We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of March 31, 2008, we had a gross liability for uncertain tax benefits of $13 million of which $10.6 million, if recognized, would affect the effective tax rate.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007, as provided in our contract. Gross oil production averaged approximately 4,200 BOE/D in the quarter ended March 31, 2008 and we are evaluating options on a quarterly basis to meet the contractual volume. The refiner will increase its total purchased volumes to 5,000 Bbl/D beginning June 29, 2008 through June 2013. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 4 to the unaudited condensed financial statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing as we are a consumer of natural gas in our operations and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by our board of directors.

Currently, our hedges are in the form of swaps and collars. However, we may use a variety of hedge instruments in the future to hedge WTI or the index gas price. We have crude oil sales contracts in place which are priced based on a correlation to WTI. Natural gas (for cogeneration and conventional steaming operations) is purchased at the SoCal border price and we sell our produced gas in Colorado and Utah at CIG, PEPL and Questar index prices.

The following table summarizes our hedge position as of March 31, 2008:

Term	Average Barrels Per Day	Floor/Ceiling Prices	Term	Average MMBtu Per Day	Average Price
Crude Oil Sales (NYMEX WTI) Collars			Natural Gas Sales (NYMEX HH TO CIG) Basis Swaps		
Full year 2008	1,000	$70.00 / $76.70	2nd Quarter 2008	17,000	$1.43
Full year 2008	10,000	$47.50 / $70.00	3rd Quarter 2008	19,000	$1.40
Full year 2009	10,000	$47.50 / $70.00	4th Quarter 2008	21,000	$1.46
Full year 2009	295	$80.00 / $91.00			
Full year 2010	1,000	$60.00 / $80.00	Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
Full year 2010	1,000	$55.00 / $76.20	1st Quarter 2009	15,400	$1.17
Full year 2010	1,000	$55.00 / $77.75	2nd Quarter 2009	15,400	$1.12
Full year 2010	1,000	$55.00 / $77.70	3rd Quarter 2009	15,400	$0.97
Full year 2010	1,000	$55.00 / $83.10	4th Quarter 2009	15,400	$1.05
Full year 2010	1,000	$60.00 / $75.00	Natural Gas Sales (NYMEX HH) Swaps		
Full year 2010	1,000	$65.15 / $75.00	2nd Quarter 2008	16,200	$8.04
Full year 2010	1,000	$65.50 / $78.50	3rd Quarter 2008	16,200	$8.04
Full year 2010	280	$80.00 / $90.00	4th Quarter 2008	16,200	$8.04
Full year 2011	270	$80.00 / $90.00	Full year 2009	15,400	$8.50
Crude Oil Sales (NYMEX WTI) Swaps			Natural Gas Sales (NYMEX HH) Collars		Floor/Ceiling Prices
Full year 2008	260	$74.00	2nd Quarter 2008	800	$7.50 / $8.40
Full year 2008	335	$92.00	3rd Quarter 2008	2,800	$7.50 / $8.50

Full year 2009	240	$71.50	4th Quarter 2008	4,800	$8.00 / $9.50

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below our floor prices which range from $47.50 to $80.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $70.00 to $91.00 per barrel on the volumes indicated above, and if 2) gas prices decline below our floor prices which range from $7.50 to $8.00 per MMBtu while still participating in any gas price increase up to the ceiling prices, which range from $8.40 to $9.50 per MMBtu on the respective volumes. These hedges improve our financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil or natural gas prices, including certain basis differentials. It also allows us to develop our long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes and allows us to borrow a higher amount under our credit facility.

While we have designated our hedges as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, it is possible that a portion of the hedge related to the movement in the WTI to California heavy crude oil price differential may be determined to be ineffective. Likewise, we may have some ineffectiveness in our natural gas hedges due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income (Loss). If the differential were to change significantly, it is possible that our hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity.

In November 2007 we entered into natural gas swaps at an index that did not correlate with the index at which the gas is sold and therefore those 2008 gas hedges are not highly effective. In January 2008 we entered into natural gas swaps which were not highly effective at inception, so we subsequently entered into basis swaps and established effectiveness at that time. Thus, we recognized an unrealized net loss of approximately $.7 million in the Statements of Income under the caption “Commodity derivatives” for the three months ended March 31, 2008.

Additionally, in 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility. These interest rate swaps have been designated as cash flow hedges.

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. Irrespective of the unrealized gains reflected in Other Comprehensive Income (Loss), the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. All of these hedges have historically been deemed to be cash flow hedges and are booked at fair value.

Based on average NYMEX futures prices as of March 31, 2008 (WTI $95.89; HH $9.96) for the term of our hedges we would expect to make pretax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	March 31, 2008 NYMEX Futures	Impact of percent change in futures prices on pretax future cash (payments) and receipts -20%	-10%	+ 10%	+ 20%
Average WTI Futures Price (2008 – 2011)	$ 95.89	$ 76.71	$ 86.30	$ 105.47	$ 115.06
Average HH Futures Price (2008 – 2009)	9.96	7.97	8.97	10.96	11.96
Crude Oil gain/(loss) (in millions)	$ (239.9)	$ (53.8)	$ (143.0)	$ (338.4)	$ (436.8)
Natural Gas gain/(loss) (in millions)	(15.0)	5.1	(5.3)	(26.9)	(37.8)
Total	$ (254.9)	$ (48.7)	$ (148.3)	$ (365.3)	$ (474.6)
Net pretax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2008 (WTI $100.42; HH $10.26)	$ (101.4)	$ (28.2)	$ (65.1)	$ (139.9)	$ (177.3)
2009 (WTI $96.26; HH $9.74)	(105.0)	(21.2)	(63.0)	(147.5)	(190.0)
2010 (WTI $94.25)	(48.2)	.2	(20.2)	(76.6)	(105.1)
2011 (WTI $93.74)	(.3)	.5	-	(1.3)	(2.2)
Total	$ (254.9)	$ (48.7)	$ (148.3)	$ (365.3)	$ (474.6)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued $200 million of 8.25% senior subordinated notes due 2016 in a public offering. Total long-term debt outstanding including our short-term Line of Credit, at March 31, 2008 was $255 million. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 1.0% to 1.75%, with the exception of the $100 million of principal for which we have hedged the interest rate at approximately 5.5% plus the credit facility's margin through June 30, 2011. Based on March 31, 2008 credit facility borrowings, a 1% change in interest rates would have an annual $.9 million after tax impact on our financial statements.

Item 4. Controls and Procedures

As of March 31, 2008, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of March 31, 2008, our Chief Executive Officer and Chief Financial Officer have concluded that our 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 us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There was no change in our internal control over financial reporting that occurred during the three months ended March 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as "plan," "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "may," "could," "goal(s)," "anticipate," or other comparable words or ph the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results and will not complete such actions on the timetable indicated.
Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 14 of our Form 10-K/A filed with the Securities and Exchange Commission, under the heading "Risk Factors" and all material changes are updated in Part II, Item 1A within this 10-Q.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings
None.

Item 1A. Risk Factors
None.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
None.

Item 3. Defaults Upon Senior Securities
None.

Item 4. Submission of Matters to a Vote of Security Holders
None.

Item 5. Other Information
None.

Item 6. Exhibits

Exhibit No.	Description of Exhibit
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 of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURE

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 thereto duly authorized.

BERRY PETROLEUM COMPANY

/s/ Shawn M. Canaday
Shawn M. Canaday
Controller
(Principal Accounting Officer)

Date: April 29, 2008