BERRY PETROLEUM CO
Form 10-Q
May 02, 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 **March 31, 2007**
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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filerx Accelerated filero Non-accelerated filero

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 18, 2007, the registrant had 42,196,896 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 18, 2007 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
FIRST QUARTER 2007 FORM 10-Q
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	March 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 95	$ 416
Short-term investments	665	665
Accounts receivable	77,893	67,905
Deferred income taxes	5,415	-
Fair value of derivatives	7,936	7,349
Assets held for sale	8,870	8,870
Prepaid expenses and other	15,813	13,604
Total current assets	116,687	98,809
Oil and gas properties (successful efforts basis), buildings and equipment, net	1,142,892	1,080,631
Fair value of derivatives	700	2,356
Other assets	16,618	17,201
	$ 1,276,897	$ 1,198,997
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 63,884	$ 69,914
Property acquisition payable	54,400	54,400
Revenue and royalties payable	13,801	45,845
Accrued liabilities	24,848	20,415
Line of credit	7,000	16,000
Other current liabilities	1,691	-
Deferred income taxes	-	745
Fair value of derivatives	22,942	8,084
Total current liabilities	188,566	215,403
Long-term liabilities:		
Deferred income taxes	102,758	103,515
Long-term debt	470,000	390,000
Abandonment obligation	30,958	26,135
Unearned revenue	1,133	1,437
Other long-term liabilities	9,290	-
Fair value of derivatives	39,936	34,807
	654,075	555,894
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; 42,191,896 shares issued and outstanding (42,098,551 in 2006)	422	421
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899)	18	18
Capital in excess of par value	53,594	50,166
Accumulated other comprehensive loss	(32,347)	(19,977)
Retained earnings	412,569	397,072

Total shareholders' equity	434,256	427,700
	$ 1,276,897	$ 1,198,997

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Month Periods Ended March 31, 2007 and 2006
(In Thousands, Except Per Share Data)

	Three months ended March 31,			
		2007		2006 (1)
REVENUES				
Sales of oil and gas	$	101,773	$	101,932
Sales of electricity		14,596		15,169
Interest and other income, net		1,110		493
		117,479		117,594
EXPENSES				
Operating costs - oil and gas production		33,610		25,738
Operating costs - electricity generation		14,170		14,332
Production taxes		3,815		3,233
Depreciation, depletion & amortization - oil and gas production		18,725		13,223
Depreciation, depletion & amortization - electricity generation		762		767
General and administrative		10,307		8,314
Interest		4,292		1,577
Commodity derivatives		-		4,828
Dry hole, abandonment, impairment and exploration		649		7,498
		86,330		79,510
Income before income taxes		31,149		38,084
Provision for income taxes		12,294		14,833
Net income	$	18,855	$	23,251
Basic net income per share	$	.43	$	.53
Diluted net income per share	$	.42	$	.52
Dividends per share	$	.075	$	.065
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)		43,916		43,988
Effect of dilutive securities:				
Equity based compensation		603		918
Director deferred compensation		112		98
Weighted average number of shares of capital stock used to calculate diluted net income per share		44,631		45,004

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended March 31, 2007 and 2006
(In Thousands)

Net income	$	18,855	$	23,251
Unrealized gains (losses) on derivatives, net of income taxes of ($7,885) and ($14,184), respectively		(11,828)		(21,276)
Reclassification of realized losses included in net income net of income taxes of ($361) and ($2,545), respectively		(542)		(3,818)
Comprehensive income	$	6,485	$	(1,843)

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

(1) The 2006 per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006. See Note 2.

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Three Month Periods Ended March 31, 2007 and 2006
(In Thousands)

	Three months ended March 31, 2007	2006
Cash flows from operating activities:		
Net income	$ 18,855	$ 23,251
Depreciation, depletion and amortization	19,487	13,990
Dry hole	188	5,209
Abandonment and impairment	(256)	(224)
Commodity derivatives	439	4,828
Stock-based compensation expense, net of taxes	1,792	1,014
Deferred income taxes, net	12,311	7,464
Other, net	209	52
(Increase) in current assets other than cash, cash equivalents and short-term investments	(13,289)	(1,936)
(Decrease) in current liabilities other than book overdraft, line of credit, property acquisition payable and fair value of derivatives	(28,119)	(28,331)
Net cash provided by operating activities	11,617	25,317
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(73,472)	(41,345)
Property acquisitions	(1,088)	(159,016)
Additions to vehicles, drilling rigs and other fixed assets	(1,018)	(5,723)
Deposit on potential sale of asset	3,000	-
Capitalized interest and other	(3,998)	-
Net cash used in investing activities	(76,576)	(206,084)
Cash flows from financing activities:		
Proceeds from issuance of line of credit	21,000	51,000
Payment of line of credit	(30,000)	(53,000)
Proceeds from issuance of long-term debt	90,000	219,750
Payment of long-term debt	(10,000)	(45,750)
Dividends paid	(3,295)	(2,867)
Change in book overdraft	(4,711)	9,881
Repurchase of shares of common stock	-	(1,802)
Proceeds from stock option exercises	1,148	1,144
Excess tax benefit and other	496	1,806
Net cash provided by financing activities	64,638	180,162
Net decrease in cash and cash equivalents	(321)	(605)
Cash and cash equivalents at beginning of year	416	1,990
Cash and cash equivalents at end of period	$ 95	$ 1,385
Supplemental non-cash activity:		
(Decrease) in fair value of derivatives:		
Current (net of income taxes of $5,358 and $5,468, respectively)	$ (8,037)	$ (8,203)
Non-current (net of income taxes of $2,889 and $11,261, respectively)	(4,333)	(16,891)
Net (decrease) to accumulated other comprehensive income	$ (12,370)	$ (25,094)

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, 2007 and December 31, 2006 and results of operations and cash flows for the three month periods ended March 31, 2007 and 2006 have been included. All such adjustments 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, 2006 financial statements. The December 31, 2006 Form 10-K 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, 2007, December 31, 2006 and March 31, 2006 is $12.5 million, $17.2 million and $11.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

In December 2004, Statement of Financial Accounting Standards (SFAS) No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. As a result, we adopted this statement beginning January 1, 2006. This standard requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. Accordingly, the adoption of SFAS No. 123(R) using the modified prospective method did not have a material impact on our condensed financial statements for the year ended December 31, 2006. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The modified prospective method was selected as described in SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, we recognized stock option compensation expense as if it had applied the fair value method to account for unvested stock options from its original effective date.

2. Stock Split

On March 1, 2006, our Board of Directors approved a two-for-one stock split to shareholders of record on May 17, 2006, subject to obtaining shareholder approval of an increase in our authorized shares. On May 17, 2006 our shareholders approved the authorized share increase and on June 2, 2006 each shareholder received one additional share for each share owned on May 17, 2006. This did not change the proportionate interest a shareholder maintained in Berry Petroleum Company on May 17, 2006. All historical shares, equity awards and per share amounts have been restated for the two-for-one stock split.

3. Recent Accounting Developments

In June 2006, the FASB issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. This interpretation requires that realization of an uncertain income tax position must be "more likely than not" (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. This interpretation is effective for fiscal years beginning after December 15, 2006, and we adopted this interpretation in the first quarter of 2007. See Note 6.

In September 2006, SFAS No. 157, *Fair Value Measurements* was issued by the Financial Accounting Standards Board (FASB). This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for our fiscal year beginning January 1, 2008, and we are currently assessing the potential impact of this Statement on our financial statements.

In September 2006, Staff Accounting Bulletin ("SAB") No. 108*, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. Registrants must quantify the impact on current period financial statements of correcting all misstatements, including both those occurring in the current period and the effect of reversing those that have accumulated from prior periods. This SAB was adopted at December 31, 2006. The adoption of SAB No. 108 had no effect on our financial position or on the results of our operations.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

3. Recent Accounting Developments (Cont'd)

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity's election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and we are evaluating this pronouncement.

4. Hedging

The related cash flow impact of all of our hedges are reflected in cash flows from operating activities. At March 31, 2007, our net fair value of derivatives liability was $54.2 million as compared to $33.2 million at December 31, 2006. At March 31, 2007, Accumulated Other Comprehensive Loss consisted of $32.3 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, 2007. Deferred net losses recorded in Accumulated Other Comprehensive Loss at March 31, 2007 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts. Our liability is primarily related to the time value of the underlying instruments and based on current prices the amount expected to be reclassified to earnings over the next 12 months is not significant.

As of February 28, 2007, we have converted 2,000 Bbl/D of our 2007 oil collars beginning on March 1, 2007 to a swap with a strike price of $60 West Texas Intermediate (WTI). This swap is considered to be an effective cash flow hedge. Additionally, we entered into oil swaps for 1,000 Bbl/D at $64.55 from March 2007 through December 2007 and entered into oil collars for 1,000 Bbl/D at $60 floor and $75 ceiling prices for 2010.

Additionally, on June 8, 2006 and July 10, 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.

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. In 2007, we reassessed our estimate as costs have increased due to demand for related services, resulting in an increase in the ARO balance at quarter end.

Under SFAS 143, the following table summarizes the change in abandonment obligation for the quarter ended March 31, 2007 (in thousands):

Beginning balance at January 1	$	26,135
Liabilities incurred		1,274
Liabilities settled		(256)
Revisions in estimated liabilities		3,272
Accretion expense		533
Ending balance at March 31	$	30,958

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

6. Income Taxes

The effective tax rate was 39% for the first quarter of 2007 compared to 38% for the fourth quarter of 2006 and 39% for the first quarter of 2006.

In June 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. The Interpretation addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of the date of adoption, we had a gross liability for uncertain tax benefits of $14.6 million of which $10.8 million if recognized, would affect the effective tax rate. We recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. As of January 1, 2007, we had accrued approximately $.9 million of interest related to our uncertain tax positions.

We have not had any material changes to our unrecognized tax benefits since adoption, nor do we anticipate significant changes to the total amount of unrecognized tax benefits within the next 12 months.

As of January 1, 2007, we remain subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	Tax Years Subject to Exam:
Federal	2003 - 2006
California	2002 - 2006
Colorado	2002 - 2006
Utah	2003 - 2006

7. Long-term and Short-term Obligations

Long-term debt
In October 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. The net proceeds from the offering were used to 1) repay approximately $145 million of borrowings under the bank credit facility, which were $170 million as of the issuance date after the application of this payment, and 2) approximately $50 million was used to pay the November 1, 2006 installment under the joint venture agreement to develop properties in the Piceance basin.

In April 2006, we completed a new unsecured five year bank credit facility agreement (the Agreement) with a banking syndicate and extended the term by one year to July 2011. The Agreement is a revolving credit facility for up to $750 million and replaces the previous $500 million facility. The current borrowing base was established at $500 million, as compared to the previous $350 million. This transaction was accounted for in accordance with Emerging Issues Task Force, (EITF) 98-14, *Debtor's Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements*.

The total outstanding debt under the credit facility's borrowing base was $270 million and the short-term line of credit was $7 million at March 31, 2007, leaving $223 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 a commitment fee of .25% to .375% on the unused portion of the credit facility annually.

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

7. Long-term and Short-term 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. Our Notes covenants limit debt to the greater of $750 million or 40% of Adjusted Consolidated Net Tangible Assets (as defined). Additionally, as long as the interest coverage ratio (as defined) is met, we may incur additional debt. We were in compliance with all such covenants as of March 31, 2007. The weighted average interest rate on the long-term outstanding credit facility borrowings at March 31, 2007 was 6.6%.

Short-term debt
In November 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, 2007 the outstanding balance under this Line of Credit was $7 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, 2007 was 6.2%.

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 accrued. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not require substantial accruals. 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.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for a portion of our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units ("base daily volume") is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade. Holly may, but is not obligated to, purchase volumes in excess of the base daily volumes when notified by us at the beginning of any contract year.

9. Assets Held for Sale

Net oil and gas properties and equipment classified as held for sale is $8.9 million at March 31, 2007 in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. On March 19, 2007 we announced that we have entered into an agreement to sell our non-core West Montalvo assets, near Ventura, California. We estimate a sales price of approximately $63 million before adjustments and expect to transfer the properties in the second quarter of 2007. The completion of the transaction is subject to certain conditions and there is no assurance that all such conditions will be satisfied.

10. Subsequent Event

We paid the third and final installment of approximately $54 million utilizing our credit facility on May 1, 2007 for the North Parachute Ranch property located in the Piceance basin.

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, 2007 and 2006 and our financial condition, liquidity and capital resources as of March 31, 2007. 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. Our mission is 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 25,490 BOE/D, up 9% from the first quarter of 2006
- Entered into a long-term crude oil sales contract for our Uinta basin, Utah production
- Restored Uinta basin production to approximately 6,000 BOE/D from a low of 3,800 BOE/D in January 2007
- Production at Midway-Sunset diatomite averaged 600 Bbl/D compared to 400 Bbl/D in the fourth quarter of 2006
- Improvements made in the Piceance basin program in personnel, services, rigs, drilling and completions
- Entered into an agreement to sell our non-core West Montalvo assets, near Ventura, California for an estimated sales price of approximately $63 million cash before adjustments

Notable Items and Expectations for the Second Quarter of 2007.

- Completing over 20 Piceance basin wells with total Piceance net production estimated at 9.6 MMcf/D
- Production at Midway-Sunset diatomite is approaching 1,000 BOE/D and the steam to oil ratio is improving
- Accelerating Poso Creek development by drilling 40 wells and installing an additional steam generator
- Transferring Montalvo properties with proceeds estimated at $63 million before adjustments
- Production is projected to average between 26,500 BOE/D and 27,500 BOE/D for the second quarter of 2007

Overview of the First Quarter of 2007. In the first quarter we were unable to sell all of our Uinta basin production due to a refinery shutdown. On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. This contract will allow us to stabilize our basis differentials on these barrels beginning on July 1, 2007 and assures us of the ability to sell this regional crude oil. Our activities in the Piceance basin included completion of a pipeline. Eleven wells have been connected since the pipeline was completed, allowing production to rise to over 8.5 net MMcf/D in April from 6.4 net MMcf/D in the first quarter of 2007.

View to the Second Quarter. Our 2007 drilling program will continue to drive our production growth. Operationally, we are focused on executing our drilling program on our Piceance basin asset where we expect to drill 16 wells during the second quarter of 2007. Furthermore, based on higher than expected performance at Poso Creek, we are planning to accelerate development there by drilling 40 wells and installing a third steam generator during the second quarter. On May 1, 2007, the final installment for our Piceance basin joint venture was paid.

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

	March 31, 2007 (1Q07)	March 31, 2006 (1Q06)	1Q07 to 1Q06 Change	December 31, 2006 (4Q06)	1Q07 to 4Q06 Change
Sales of oil	$ 80.9	$ 83.3	(3%)	$ 84.2	(4%)
Sales of gas	20.9	18.6	12%	17.6	19%
Total sales of oil and gas	$ 101.8	$ 101.9	-%	$ 101.8	-%
Sales of electricity	14.6	15.2	(4%)	13.4	9%
Interest and other income, net	1.1	.5	120%	1.0	10%
Total revenues and other income	$ 117.5	$ 117.6	-%	$ 116.2	1%
Net income	$ 18.9	$ 23.3	(19%)	$ 19.1	(1%)
Net income per share (diluted)	$ .42	$ .52	(19%)	$ .43	(2%)

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. For the three months ended March 31, 2007, gas sales improved while oil sales declined when compared to three months ended March 31, 2006. Improvement to gas sales is due to higher production primarily from our Piceance basin acquisition, partially offset by lower gas prices. Oil sales decreased due to lower prices partially offset by higher volumes primarily from our NMWSS and Poso Creek properties.

Similarly, for the three months ended March 31, 2007 compared to the three months ended December 31, 2006, gas sales improved while oil sales declined. Improvement in realized gas prices during the first three months of 2007 were due to increased weather related demand and a tighter supply and demand balance, while oil sales declined primarily due to lower production.

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

	March 31, 2007	%	March 31, 2006	%	December 31, 2006	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	16,140	63	15,407	66	16,833	63
Light Oil Production (Bbl/D)	3,233	13	3,303	14	3,363	13
Total Oil Production (Bbl/D)	19,373	76	18,710	80	20,196	76
Natural Gas Production (Mcf/D)	36,704	24	28,507	20	40,157	24
Total (BOE/D)	25,490	100	23,461	100	26,889	100
Per BOE:						
Average sales price before hedging	$ 43.62		$ 50.04		$ 41.53	
Average sales price after hedging	43.84		48.45		42.00	
Oil, per Bbl:						
Average WTI price	$ 58.23		$ 63.48		$ 60.17	
Price sensitive royalties	(3.74)		(5.41)		(4.28)	
Quality differential and other	(8.78)		(6.36)		(9.06)	
Crude oil hedges	.03		(2.04)		(.01)	
Average oil sales price after hedging	$ 45.74		$ 49.67		$ 46.82	
Gas, per MMBtu:						
Average Henry Hub price	$ 7.18		$ 7.92		$ 7.24	
Natural gas hedges	.13		(.03)		.33	
Location, quality differentials and other	(.70)		(1.05)		(2.68)	
Average gas sales price after hedging	$ 6.61		$ 6.84		$ 4.89	

Gas Basis Differential. The gas prices in the Rockies continue to be volatile due to various factors, including takeaway pipeline capacity, supply volumes, and regional demand issues. We expect the basis differential to narrow upon the startup of the Rockies Express pipeline which is anticipated in 2008. We have contracted 10,000 Mcf/D on this pipeline to provide assurance of gas delivery. The Colorado Interstate Gas (CIG) basis differential averaged $1.18 below Henry Hub (HH) and ranged from $.51 to $1.67 below HH in the first quarter. Although related to CIG, the actual basin price varies. Gas from the DJ basin was sold slightly above the CIG price, Piceance basin gas was slightly below the CIG price while Uinta basin gas sold for approximately $.40 below CIG pricing.

Oil Contracts. Utah - As of March 31, 2007, our Utah light crude oil is sold under multiple contracts with different purchasers for varying pricing terms and ranging from one month to six months. In April 2007, contracts were in place to sell approximately 5,000 BOE/D during the month. These contracts have marginally improved since December 31, 2006 and are currently priced at approximately $12 to $17 per barrel below WTI with certain volumes tied to field posting, and in some cases our realized price is further reduced by transportation charges. As operator we deliver all produced volumes pursuant to these contracts, although our working interest partners or royalty owners have the right to take their respective volumes in kind and market their own volumes. Our net volumes from our Brundage Canyon properties approximate 80% of the total gross volumes. Assuming all the Brundage Canyon wells are producing, the gross production could exceed these contracted volumes. Our Utah crude oil is a paraffinic crude and can be processed efficiently by only a limited number of refineries.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 Bbl/D beginning July 1, 2007. Holly has begun to take delivery of approximately 1,000 Bbl/D in the first quarter of 2007, which stabilizes our realized sales price and reduces our transportation costs. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI and approximates our expected field posted price of $13 to $16 below WTI. This contract provides the pricing assurance we need to proceed with the long-term development of our Uinta basin assets. From October 1, 2003 through April 30, 2006 we were able to sell our Utah crude oil at approximately $2.00 per barrel below WTI and from May 1, 2006 through September 30, 2006, we were selling the majority of our Utah crude at approximately $9.00 per barrel below WTI. We may adjust our capital expenditures in the Uinta basin due to various factors, including the timing of refinery demand for the Uinta basin barrels and the actual or expected change in our realized price.

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 economic production of heavy oil. Revenue and operating costs for the three months ended March 31, 2007 were down from the three months ended March 31, 2006 due to 6% lower electricity prices and 12% lower fuel gas cost, respectively. Conversely, revenue and operating costs in the three months ended March 31, 2007 were up from the three months ended December 31, 2006 due to 8% higher electricity prices and 4% higher natural gas prices, respectively. The following table is for the three months ended:

	March 31, 2007	March 31, 2006	December 31, 2006
Electricity			
Revenues (in millions)	$ 14.6	$ 15.2	$ 13.4
Operating costs (in millions)	$ 14.2	$ 14.3	$ 12.1
Electric power produced - MWh/D	2,117	2,080	2,093
Electric power sold - MWh/D	1,914	1,884	1,861
Average sales price/MWh	$ 81.08	$ 85.93	$ 75.05
Fuel gas cost/MMBtu (including transportation)	$ 6.70	$ 7.65	$ 6.44

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, 2007	March 31, 2006	December 31, 2006	March 31, 2007	March 31, 2006	December 31, 2006
Operating costs - oil and gas production	$ 14.65	$ 12.19	$ 13.69	$ 33,610	$ 25,738	$ 33,804
Production taxes	1.66	1.53	1.15	3,815	3,233	2,840
DD&A - oil and gas production	8.16	6.26	8.24	18,725	13,223	20,335
G&A	4.49	3.94	4.55	10,307	8,314	11,231
Interest expense	1.69	.75	1.27	4,292	1,577	3,503
Total	$ 30.65	$ 24.67	$ 28.90	$ 70,749	$ 52,085	$ 71,713

Our total operating costs, production taxes, G&A and interest expenses for the three months ended March 31, 2007, stated on a unit-of-production basis, increased 24% over the three months ended March 31, 2006 and increased 6% over the three months ended December 31, 2006. The changes were primarily related to the following items:

· Operating costs: Operating costs per BOE in the first quarter of 2007 were 20% higher than the first quarter of 2006 primarily due to an increase in steam costs, company and contract labor as well as transportation, compression and gathering costs. Similarly, operating costs per BOE were 7% higher in the first quarter of 2007 as compared to the fourth quarter of 2006, as production volumes were down. Cost pressures do remain, but we are working to offset them with improved efficiencies. The cost of our steaming operations on our heavy oil properties in California varies depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

	March 31, 2007	March 31, 2006	1Q07 to 1Q06 Change	December 31, 2006	1Q07 to 4Q06 Change
Average volume of steam injected (Bbl/D)	86,132	75,138	15%	85,349	1%
Fuel gas cost/MMBtu (including transportation)	$ 6.70	$ 7.65	(12%)	$ 6.44	4%

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 2007 of approximately 90,000 to 95,000 barrels of steam per day (BSPD). Natural gas prices impact our cost structure in California by approximately $1.60 per California BOE for each $1.00 change in natural gas price.

· Production taxes: Our production taxes have increased over 2006 as the value of our oil and natural gas assets has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the cost of 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, in general, to track the commodity price.

· Depreciation, depletion and amortization: DD&A increased per BOE in the three months ended March 31, 2007 compared to the same period in the prior year due to an increase in capital spending over the last year and particularly more extensive development in fields with higher drilling costs and leasehold acquisition costs. Our capital program is also experiencing cost pressures in our labor and for goods and services commensurate with other energy developers. As these costs increase, our DD&A rates per BOE will also increase.

· General and administrative: Approximately 70% of our G&A is compensation or compensation related costs. To remain competitive in workforce compensation and achieve our growth goals, our general and administrative cost increased significantly due to additional staffing, higher compensation levels, bonuses, stock compensation and benefit costs. We also incurred higher employee travel and other G&A costs associated with our growth activities.

· Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was $477 million at March 31, 2007 compared to $406 million at December 31, 2006. Our average borrowings increased during the three months ended March 31, 2007 as a result of our capital expenditure program and due to the annual payment of a price-based royalty for $38 million. Beginning in 2006, a certain portion of our interest cost related to our Piceance basin acquisition and joint venture has been capitalized into the basis of the assets, and we anticipate a portion will continue to be capitalized until the remainder of our probable reserves have been recategorized to proved developed reserves. For the quarter ended March 31, 2007, $4 million has been capitalized and we expect to capitalize approximately $20 million of interest cost during the full year of 2007.

Estimated 2007 Oil and Gas Operating, G&A and Interest Expenses.

		Anticipated range in 2007 per BOE
Operating costs-oil and gas production *(1)*	$	14.50 to 15.50
Production taxes		1.50 to 2.00
DD&A		7.75 to 8.75
G&A		3.50 to 4.00
Interest expense		1.00 to 2.00
Total	$	28.25 to 32.25

(1) Assuming natural gas prices of approximately NYMEX HH $7.50 MMBtu, we plan to inject approximately 15% greater steam levels in 2007 compared to 2006 levels.

Income Taxes. See Note 6 to the unaudited condensed financial statements. Our effective tax rate will be similar in 2007 as compared to 2006. We experienced an effective tax rate in the three months ended March 31, 2007 of 39%, which is in line with our projections.

Development, Exploitation and Exploration Activity. We drilled 124 gross (88 net) wells during the first quarter of 2007, realizing a gross success rate of 99 percent. Excluding any future acquisitions, our targeted 2007 developmental capital budget is between $227 million and $267 million. As of March 31, 2007, we have five rigs drilling on our properties under long-term contracts and have one more rig scheduled to begin in mid-2007.

Drilling Activity. The following table sets forth certain information regarding drilling activities for the three months ended March 31, 2007:

	Gross Wells	Net Wells
SMWSS	20	20
NMWSS	11	11
Socal	18	18
Piceance	18	5
Uinta	15	13
DJ *(1)*	42	21
Totals	**124**	**88**

(1) Includes 1 gross well (.5 net well) that was a dry hole in Yuma County, Colorado.

<u>Production</u>

California's three asset teams are South Midway-Sunset (SMWSS, which has been realigned to include Ethel D), North Midway-Sunset (NMWSS) (which includes diatomite) and Southern California (Socal) (which includes Poso Creek, Placerita and Montalvo). The Rocky Mountain/Mid-Continent region's three asset teams are Piceance, Uinta and DJ basins.

SMWSS, San Joaquin Valley Basin (SJVB) - During the three months ended March 31, 2007, production averaged approximately 9,900 Bbl/D compared to approximately 10,800 Bbl/D and 10,700 Bbl/D during the three month periods ended March 31, 2006 and December 31, 2006, respectively. During the three months ended March 31, 2007, we completed four horizontal infill wells and improved subsurface steam monitoring to determine best heat placement into the remaining oil column to maximize recovery and value. Additionally, a number of horizontal wells were pulled off production for cyclic steaming. Cyclic steaming of these horizontal wells is necessary to place steam effectively into the remaining oil column. In the second quarter of 2007, we plan to drill approximately 14 infill horizontal wells. Increased production from these activities is expected to slow the natural decline. We expect to manage our decline rate to approximately 6% to 7% for 2007.

We have completed our 2007 drilling program on our Ethel D property and production has increased by over 200 Bbl/D. We may expand our program depending on reservoir performance.

NMWSS, SJVB - Our Midway-Sunset diatomite oil project is performing above expectations due to a more aggressive approach in our use of steam. During the three months ended March 31, 2007, production from the diatomite project averaged approximately 600 Bbl/D up from approximately 200 Bbl/D and 400 Bbl/D during the three month periods ended March 31, 2006 and December 31, 2006, respectively. Our 2007 capital is focused on drilling the diatomite first phase development wells and adding steam generation equipment and various facilities. Diatomite wells will not begin to be drilled until the third quarter of 2007.

Socal, SJVB and Los Angeles Basin - Poso Creek is performing solidly above plan due to strong steam flood performance and our infill drilling. During the three months ended March 31, 2007, production averaged approximately 1,500 Bbl/D up from approximately 600 Bbl/D and 1,400 Bbl/D during the three month periods ended March 31, 2006 and December 31, 2006, respectively. We are planning to accelerate development drilling with over 70 infill producing wells this year, expanding the steam drive by 14 patterns and installing a third steam generator in the second quarter of 2007.

Piceance Basin, Colorado - We currently have four drilling rigs operating in the basin and expect to maintain this level for the remainder of the year. Newly constructed pipelines to the mesa plateaus were completed late in the first quarter and since completion, three North Parachute Ranch wells and eight Garden Gulch wells have been put into production. Twelve additional wells are forecasted to be drilled and connected by the end of the second quarter of 2007. Average daily production in the Piceance basin for the first quarter was 6.4 net MMcf/D. The recent well connects have increased April monthly production to over 8.5 net MMcf/D. Significant progress has been made to lower the days required to drill wells. Construction has begun on the Garden Gulch road extension, which, coupled with the mountain road, will greatly improve access to our operations on the Garden Gulch acreage.

Uinta Basin, Utah - Our 2007 capital is directed at additional Brundage Canyon 40-acre development wells, drilling the Ashley Forest extension to the south of Brundage Canyon, continued Lake Canyon assessment and drilling 20-acre infill wells in Brundage Canyon. During the first quarter, we drilled 13 net wells in Brundage Canyon. Well performance results continue to be positive and preliminary results from four 20-acre pilot wells indicate the possibility of new production opportunities.

Average daily production during the first quarter from all Uinta basin assets was 4,800 net BOE/D. In the fourth quarter of 2006, oil sales were interrupted due to refinery and trucking limitations. The refinery resumed operations in mid-January 2007. Improved market conditions late in the first quarter resulted in a daily production exit rate of 6,100 net BOE/D for the quarter. We continue to have one drilling rig operating in the basin. In February 2007, we signed a six year oil contract with Holly for 3,200 BOE/D starting in July 2007 with up to 5,000 BOE/D through June 30, 2013 upon the certified completion of their refinery upgrade. This contract along with our other oil marketing arrangements provides us the ability to sell all of our crude oil production in the Uinta basin.

Post winter season access to our Ashley Forest acreage and Lake Canyon area will open up in May of 2007, with our second and third quarter drilling focusing in these areas. Six drilling permits have been received for Ashley Forest and four permits received for Lake Canyon wells with an additional 16 permits anticipated in the second quarter to support the mid-May to December drilling window.

In December 2004, we entered into a development agreement with an industry partner to develop their Coyote Flats prospect. In the first and early second quarter of 2006, we established gas sales from three Ferron wells. The combined net production from the three wells is approximately 1.0 MMcf/D. We will continue the production tests to further assess the Ferron’s potential at Coyote Flats. As the result of establishing production in the three wells, we were assigned a 50% interest in approximately 43,700 gross acres from our industry partner.

DJ Basin - Our first quarter activity in the DJ basin has focused on Niobrara development drilling in Yuma County, Colorado. Production early in the quarter was hampered by severe snow on Colorado’s eastern plains. Average daily production in the DJ for the first quarter was 17.4 net MMcf/D and by the end of the quarter, production has recovered to approximately 18 MMcf/D.

We drilled 41 Niobrara wells during the first quarter of 2007. In addition, 28.5 square miles of 3-D seismic data was acquired in the quarter. This 3-D data and the existing drilling location inventory supports the 2007 drilling program of 168 wells.

Company Owned Drilling Rigs. During 2005 and 2006, we purchased three drilling rigs, two of which are drilling for us. Owning these rigs allows us to successfully meet a portion of our drilling needs in the Uinta and Piceance basins.

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 have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices. In the second quarter of 2006, we revised our senior unsecured revolving credit facility to increase our maximum credit amount under the facility to $750 million and increased our current borrowing base to $500 million. On October 24, 2006, we completed the sale of $200 million of ten year 8.25% senior subordinated notes and paid down our borrowings under our facility by $141 million. As of March 31, 2007, we had total borrowings under the senior unsecured revolving credit facility and senior unsecured money market line of credit of $277 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, drilling outcomes and/or changes in commodity prices that influence our decision to change capital expenditures to closely match operating cash flows. Excess cash generated from operations is expected to be applied toward capital expenditures, debt reduction or other corporate purposes.

Management is closely monitoring the capital development program in relation to estimated cash flows and expects to commit capital in the $227 million to $267 million range, excluding acquisitions. The capital development program may be revised due to lower commodity price expectations, timing of crude deliveries out of the Uinta basin, equipment availability, permitting or other factors. We have reevaluated the development plan in the Piceance basin to maximize capital efficiency by minimizing rig moves. Consequently, we estimate that companywide proved reserves will approximate 170 to 180 million BOE at year end 2007, including the effect of the expected sale of the Montalvo assets which consist of 7 million BOE of reserves. During the three months ended March 31, 2007, capital expenditures totaled $75.5 million of which $28 million related to the 2007 capital budget and $47.5 million related to the 2006 capital budget.

Our 2007 expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2007, we plan to invest up to approximately $176 million, or 66%, in our Rocky Mountain/Mid-Continent region assets, and up to $91 million, or 34%, in our California assets.

On March 19, 2007 we announced that we have entered into an agreement to sell our non-core West Montalvo assets, near Ventura, California. We estimate a sales price of approximately $63 million before adjustments and expect to transfer the assets in the second quarter of 2007. Production from the property is approximately 700 BOE/D, which is less than 3% of current production and, as of December 31, 2006, the property had 7 million BOE of proved reserves which is less than 5% of the 2006 year end total of 150 million BOE. The completion of the transaction is subject to certain conditions and there is no assurance that all such conditions will be satisfied.

Dividends. Our annual dividend is currently $.30 per share, payable quarterly in March, June, September and December.

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. Combined crude oil and natural gas prices increased in the first three months of 2007 (see graphs on page 11) and production decreased since December 2006 by 5%.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We used our long-term borrowings under our senior unsecured revolving 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, 2007 (1Q07)	March 31, 2006 (1Q06)	1Q07 to 1Q06	December 31, 2006 (4Q06)	1Q07 to 4Q06

			Change		Change
Average production (BOE/D)	25,490	23,461	9%	26,889	(5%)
Average oil and gas sales prices, per BOE after hedging	$ 43.84	$ 48.45	(10%)	$ 42.00	4%
Net cash provided by operating activities	$ 12	$ 25	(52%)	$ 58	(79%)
Working capital, excluding line of credit	$ (65)	$ (50)	(30%)	$ (101)	36%
Sales of oil and gas	$ 102	$ 102	-%	$ 102	-%
Long-term debt, including line of credit	$ 477	$ 259	84%	$ 406	17%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 76	$ 206	(63%)	$ 127	(40%)
Dividends paid	$ 3.3	$ 2.9	14%	$ 3.3	-%

Contractual Obligations. Our contractual obligations as of March 31, 2007 are as follows (in millions):

	Total	2007	2008	2009	2010	2011	Thereafter
Long-term debt and interest	$ 715.1	$ 34.3	$ 34.3	$ 34.3	$ 34.3	$ 295.4	$ 282.5
Abandonment obligations	30.9	.7	.9	1.0	1.0	1.0	26.3
Property acquisition payable	54.4	54.4	-	-	-	-	-
Operating lease obligations	13.9	1.4	1.7	1.4	1.4	1.4	6.6
Drilling and rig obligations	89.8	19.6	25.3	42.7	2.2	-	-
Firm natural gas transportation contracts	72.7	3.6	7.6	8.5	8.7	8.7	35.6
Total	$ 976.8	$ 114.0	$ 69.8	$ 87.9	$ 47.6	$ 306.5	$ 351.0

Long-term debt and interest - Our credit facility borrowings and related interest of approximately 6.6% can be paid before its maturity date without significant penalty on borrowings under our credit facility. Our 8.25% senior subordinated notes mature in November 2016, but are not redeemable until November 1, 2011 and are not redeemable without any premium until November 1, 2014.

Operating leases - We lease corporate and field offices in California, Colorado and Texas. We lease an airplane for business travel under a ten year operating lease beginning December 2006.

Drilling obligation - We intend to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the four year contract, beginning in 2006. Our minimum expenditure obligation under our exploration and development agreement is $9.6 million. Also included above, under our June 2006 joint venture agreement in the Piceance basin, we must have 120 wells drilled by 2010 to avoid penalties of $.2 million per well or a maximum of $24 million.

Drilling rig obligation - We are obligated in operating lease agreements for the use of multiple drilling rigs.

Firm natural gas transportation - We have one firm transportation contract which provides us additional flexibility in securing our natural gas supply for California operations. This allows us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California. We also have several long-term transportation contracts which provide us with physical access to interstate pipelines to move gas from our producing areas to markets.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units (“base daily volume”) is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade. Holly may, but is not obligated to, purchase volumes in excess of the base daily volumes when notified by us at the beginning of any contract year.

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, from time to time we enter into crude oil and natural gas hedge contracts. 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 any 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 and Questar index prices, respectively.

The following table summarizes our hedge position as of March 31, 2007:

Term	Average Barrels Per Day	Floor/Ceiling Prices	Term	Average MMBtu Per Day	Floor/Ceiling Prices
Crude Oil Sales (NYMEX WTI) Collars			**Natural Gas Sales (NYMEX HH) Collars**		
Full year 2007	8,000	$47.50 / $70.00	2nd Quarter 2007	13,000	$8.00 / $8.82
Full year 2008	10,000	$47.50 / $70.00	3rd Quarter 2007	14,000	$8.00 / $9.10
Full year 2009	10,000	$47.50 / $70.00	4th Quarter 2007	15,000	$8.00 / $11.39
Full year 2010	5,000	$56.00 / $78.95	1st Quarter 2008	16,000	$8.00 / $15.65
Full year 2010	1,000	$60.00 / $75.00	2nd Quarter 2008	17,000	$7.50 / $8.40
			3rd Quarter 2008	19,000	$7.50 / $8.50
			4th Quarter 2008	21,000	$8.00 / $9.50
			Natural Gas Sales (NYMEX HH TO CIG)		
Swaps		Price	**Basis Swaps**		Price
2nd through 4th quarter 2007	1,000	$64.55	April 2007	13,000	$1.77
2nd through 4th quarter 2007	2,000	$60.00	May 2007	13,000	$1.70
			June 2007	13,000	$1.69
			July 2007	14,000	$1.56
			August 2007	14,000	$1.51
			September 2007	14,000	$1.58
			October 2007	15,000	$1.63
			November & December 2007	15,000	$1.71
			1st Quarter 2008	16,000	$1.74
			2nd Quarter 2008	17,000	$1.43
			3rd Quarter 2008	19,000	$1.40
			4th Quarter 2008	21,000	$1.46

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below $47.50 per barrel while still participating in any oil price increase up to $78.95 per barrel on these volumes and if 2) gas prices decline below approximately $8 per MMBtu. 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. 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 senior unsecured revolving 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. While we believe that the differential will narrow and move closer toward its historical level over time, there are no assurances as to the movement in the differential. 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.

We entered into derivative contracts (natural gas swaps and collar contracts) on March 1, 2006 that did not qualify for hedge accounting under SFAS 133 because the price index for the location in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in the first quarter of 2006 at their fair value on the balance sheet and we recognized an unrealized net loss of approximately $4.8 million on the income statement under the caption "Commodity derivatives." We entered into natural gas basis swaps on the same volumes and maturity dates as the previous hedges in May 2006 which allowed for these derivatives to be designated as cash flow hedges going forward, causing an unrealized net gain of $5.6 million to be recognized in the second quarter of 2006. The difference of $.8 million was recorded in other comprehensive income at the date the hedges were designated.

On June 8, 2006 and July 10, 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, 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 with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

Based on NYMEX futures prices as of March 31, 2007, (WTI $68.72; HH $8.50) we would expect to make pre-tax 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, 2007 NYMEX Futures	Impact of percent change in futures prices on earnings -20%	-10%	+ 10%	+ 20%
Average WTI Futures Price (2007 - 2010)	$ 68.72	$ 54.98	$ 61.85	$ 75.59	$ 82.46
Crude Oil gain/(loss) (in millions)	(5.7)	11.6	.1	(69.6)	(147.6)
Average HH Futures Price (2007 - 2008)	8.50	6.80	7.65	9.35	10.2
Natural Gas gain (in millions)	5.7	16.1	8.8	3.3	(2.2)
Net pre-tax future cash (payments) and receipts by year (in millions):					
2007 (WTI $68.27; HH $8.24)	$ .6	$ 16.8	$ 8.3	$ (16.6)	$ (38.6)
2008 (WTI $69.97; HH $8.70)	(.6)	5.0	.6	(28.0)	(57.7)
2009 (WTI $69.05)	-	-	-	(21.7)	(46.9)
2010 (WTI $67.49)	-	5.9	-	-	(6.6)
Total	$ -	$ 27.7	$ 8.9	$ (66.3)	$ (149.8)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. On October 24, 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, 2007 was $477 million. Interest on amounts borrowed under our revolving 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 a hedge in place to fix the interest rate at approximately 5.5% plus the senior unsecured revolving credit facility's margin through June 30, 2011. Based on March 31, 2007 credit facility borrowings, a 1% change in interest rates would have an annual $1.1 million after tax impact on our financial statements.

Item 4. Controls and Procedures

As of March 31, 2007, we have carried out an evaluation under the supervision of, and with the participation of 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 and Exchange Act of 1934, as amended.

Based on their evaluation as of March 31, 2007, 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 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 during the most recently completed calendar quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "may," "could," "goal(s),", "forecast," "anticipate," or other comparable phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. 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 15 of our Form 10-K 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

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next six years are uncertain and there is no assurance that we ill be able to consistently meet the minimum requirement. On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, we will begin delivering 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units ("base daily volume") is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade.

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
10.1* Purchase and sale agreement between the Company and Venoco, Inc. dated March 19, 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 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.

* Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

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: May 2, 2007