PARALLEL PETROLEUM CORP
Form 10-Q
August 04, 2009

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2009 or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition period from __________ to __________
Commission File Number 000-13305
PARALLEL PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	75-1971716
(State of other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1004 N. Big Spring, Suite 400, Midland, Texas	79701
(Address of Principal Executive Offices)	(Zip Code)

(432) 684-3727

(Registrant s telephone number, including area code)
Not Applicable

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes o No o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

APPLICABLE ONLY TO ISSUERS INVOLVED IN BANKRUPTCY
PROCEEDINGS DURING THE PRECEDING FIVE YEARS:

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ¨ No ¨

As of July 30, 2009, the registrant had 41,646,445 shares of common stock outstanding.

INDEX

Table of Contents

PART 1 FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PARALLEL PETROLEUM CORPORATION

Balance Sheets

(unaudited)

($ in thousands)

Assets

	June 30, 2009	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 28,774	$ 36,303
Short-term investments	5,000	5,002
Accounts receivable:		
Oil and natural gas sales	10,084	13,399
Joint interest owners and other, net of allowance for doubtful account of $50	1,596	2,805
Affiliates and joint ventures	6	12
	11,686	16,216
Other current assets	702	430
Derivatives	8,825	22,665
Total current assets	54,987	80,616
Property and equipment, at cost:		
Oil and natural gas properties, full cost method (including $136,046 and $137,202 not subject to depletion)	888,676	878,722
Other	3,314	3,172
	891,990	881,894
Less accumulated depreciation, depletion and amortization	(533,171)	(490,566)
Net property and equipment	358,819	391,328
Restricted cash	82	81
Investment in pipeline venture	349	337
Other assets, net of accumulated amortization of $1,754 and $1,443	3,312	3,566
Deferred tax asset	71,336	60,567
Derivatives	8,616	14,081
	$ 497,501	$ 550,576

The accompanying notes are an integral part of these Financial Statements.

(1)

Table of Contents

PARALLEL PETROLEUM CORPORATION
Balance Sheets (continued)
(unaudited)
($ in thousands)
Liabilities and Stockholders Equity

	June 30, 2009	December 31, 2008
Current liabilities :		
Accounts payable trade	$ 2,103	$ 13,522
Accrued liabilities	14,423	21,780
Accrued interest on senior notes	6,406	6,407
Asset retirement obligations	158	158
Derivative obligations	4,737	3,004
Put premium obligations	1,036	628
Deferred tax liability	1,058	6,597
Total current liabilities	29,921	52,096
Long-term liabilities:		
Revolving credit facility	225,000	225,000
Senior notes (principal amount $150,000)	146,166	145,890
Asset retirement obligations	9,846	11,221
Derivative obligations	5,041	5,136
Put premium obligations	3,031	3,655
Termination obligation	385	532
Total long-term liabilities	389,469	391,434
Commitments and contingencies		
Stockholders equity:		
Series A preferred stock par value $0.10 per share, authorized 50,000 shares		
Common stock par value $0.01 per share, authorized 60,000,000 shares, issued and outstanding 41,597,161 for 2009 and 2008	415	415
Additional paid-in capital	201,198	200,132
Retained deficit	(123,502)	(93,501)
Total stockholders equity	78,111	107,046
	$ 497,501	$ 550,576

The accompanying notes are an integral part of these Financial Statements.

(2)

Table of Contents

PARALLEL PETROLEUM CORPORATION
Statements of Operations
(unaudited)
(in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Oil and natural gas revenues:				
Oil and natural gas sales	$ 19,861	$ 56,075	$ 38,090	$ 100,016
Costs and expenses:				
Lease operating expense	5,541	7,254	13,627	14,233
Production taxes	761	2,996	1,334	5,285
General and administrative	3,281	3,265	6,714	5,833
Depreciation, depletion and amortization	5,398	10,483	12,179	19,835
Impairment of oil and natural gas properties			30,426	
Total costs and expenses	14,981	23,998	64,280	45,186
Operating income (loss)	4,880	32,077	(26,190)	54,830
Other income (expense), net:				
Loss on derivatives not classified as hedges	(13,286)	(71,609)	(7,521)	(93,495)
Interest and other income	30	32	99	65
Interest expense, net of capitalized interest	(6,360)	(5,368)	(12,690)	(10,886)
Other expense	(5)	(1)	(5)	(1)
Equity in gain of pipelines and gathering system ventures		165	1	382
Total other income (expense), net	(19,621)	(76,781)	(20,116)	(103,935)
Loss before income taxes	(14,741)	(44,704)	(46,306)	(49,105)
Income tax benefit	5,101	15,499	16,305	17,160
Net loss	$ (9,640)	$ (29,205)	$ (30,001)	$ (31,945)
Net loss per common share:				
Basic	$ (0.23)	$ (0.70)	$ (0.72)	$ (0.77)
Diluted	$ (0.23)	$ (0.70)	$ (0.72)	$ (0.77)
Weighted average common shares outstanding:				
Basic	41,597	41,446	41,597	41,359

Diluted	41,597	41,446	41,597	41,359

The accompanying notes are an integral part of these Financial Statements.

(3)

Table of Contents

PARALLEL PETROLEUM CORPORATION
Statements of Stockholders Equity
As of December 31, 2008 and for the six months ended June 30, 2009
(unaudited)
(in thousands)

	Common stock		Additional		Total
	Number of shares	Amount	paid-in capital	Retained deficit	stockholders equity
Balance, December 31, 2008	41,597	$ 415	$ 200,132	$ (93,501)	$ 107,046
Restricted stock expense			45		45
Stock option expense			1,021		1,021
Net loss				(30,001)	(30,001)
Balance, June 30, 2009	41,597	$ 415	$ 201,198	$ (123,502)	$ 78,111

The accompanying notes are an integral part of these Financial Statements.

(4)

Table of Contents

PARALLEL PETROLEUM CORPORATION
Statements of Cash Flows
Six Months Ended June 30, 2009 and 2008
(unaudited)
($ in thousands)

	2009	2008
Cash flows from operating activities:		
Net loss	$ (30,001)	$ (31,945)
Adjustments to reconcile net loss to net cash (used in) provided by operating activities:		
Depreciation, depletion and amortization	12,179	19,835
Gain on sale of automobiles		(4)
Impairment of oil and natural gas properties	30,426	
Accretion of asset retirement obligation	425	187
Accretion of senior notes discount	276	247
Deferred income tax benefit	(16,305)	(17,160)
Loss on derivatives not classified as hedges	7,521	93,495
Amortization of deferred financing cost	312	374
Accretion of interest on put obligations	105	6
Common stock issued to directors		160
Restricted stock expense	45	57
Stock option expense	1,021	227
Equity in gain of pipelines and gathering system ventures	(1)	(382)
Changes in assets and liabilities:		
Other assets, net	632	(854)
Restricted cash	(1)	(2)
Accounts receivable	4,530	(8,316)
Other current assets	(272)	(99)
Accounts payable and accrued liabilities	(11,380)	14,069
Net cash (used in) provided by operating activities	(488)	69,895
Cash flows from investing activities:		
Additions to oil and natural gas properties	(19,301)	(123,727)
Additions to other property and equipment	(142)	(273)
Settlements on derivative instruments	10,785	(22,839)
Short-term investments	(5,000)	
Maturity of short-term investments	5,002	
Net investment in pipelines and gathering system ventures	(11)	(15)
Net cash used in investing activities	(8,667)	(146,854)
Cash flows from financing activities:		
Borrowings from bank line of credit		77,000
Deferred financing cost	(690)	(270)
Proceeds from exercise of stock options		1,323
Settlements on derivative instruments with financing elements	2,316	

Net cash provided by financing activities	1,626	78,053
Net (decrease) increase in cash and cash equivalents	(7,529)	1,094
Cash and cash equivalents at beginning of period	36,303	7,816
Cash and cash equivalents at end of period	$ 28,774	$ 8,910

The accompanying notes are an integral part of these Financial Statements.

Parallel Petroleum Corporation
Statements of Cash Flows (continued)
Six Months Ended June 30, 2009 and 2008
(unaudited)
($ in thousands)

	2009	2008
Non-cash financing and investing activities:		
Deferred purchase of derivative puts	$	$ 3,325
Oil and natural gas properties asset retirement obligations	$ (1,800)	$ 482
Additions to oil and natural gas properties accrued	$ (7,400)	$ 1,000
Termination obligation capitalized to oil and natural gas properties	$ (147)	$
Property transfer:		
Transfer to oil and natural gas properties	$	$ 8,707
Transfer from equity investment	$	$ (8,707)
Other transactions:		
Interest paid	$ 13,040	$ 9,901
Taxes paid	$ 75	$

The accompanying notes are an integral part of these Financial Statements.

Table of Contents

NOTES TO FINANCIAL STATEMENTS

NOTE 1. DESCRIPTION OF BUSINESS NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Parallel Petroleum Corporation, or Parallel , was incorporated in Texas on November 26, 1979, and reincorporated in the State of Delaware on December 18, 1984.

Parallel is engaged in the acquisition, development and exploitation of long-lived oil and natural gas reserves and, to a lesser extent, exploring for new oil and natural gas reserves. The majority of our producing properties are in the:

Permian Basin of west Texas and New Mexico; and

Fort Worth Basin of north Texas.

The financial information included herein is unaudited. The balance sheet as of December 31, 2008 has been derived from our audited Financial Statements as of December 31, 2008. The unaudited financial information includes all adjustments (consisting solely of normal recurring adjustments), which are, in the opinion of management, necessary for a fair statement of the results of operations for the interim periods. The results of operations for the interim period are not necessarily indicative of the results to be expected for an entire year. Certain 2008 amounts have been conformed to the 2009 financial statement presentation.

Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted in this Quarterly Report on Form 10-Q under certain rules and regulations of the Securities and Exchange Commission. The financial statements included in this report should be read in conjunction with the audited Financial Statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2008.

Unless otherwise indicated or unless the context otherwise requires, all references to we , us , our , Parallel , or Company mean the registrant, Parallel Petroleum Corporation.

NOTE 2. STOCKHOLDERS EQUITY

Parallel accounts for stock based compensation in accordance with the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)).

Parallel awards incentive stock options, nonqualified stock options, restricted stock and stock awards to selected key employees, officers, and directors. Stock options are awarded at exercise prices equal to the closing price of our common stock on the date of grant. These options vest over a period of two to ten years with a ten-year exercise period. As of June 30, 2009, options expire beginning in 2011 and extending through 2019. The stock options and restricted stock awards fair values are described below for each grant. Stock based compensation expense is classified as a general and administrative expense in the Statements of Operations.

Options

For the three months ended June 30, 2009 and 2008, we recognized compensation expense of approximately $499,000 and $145,000, respectively, with a tax benefit of approximately $170,000 and $49,000, respectively. For the six months ended June 30, 2009 and 2008, we recognized compensation expense of approximately $1.0 million and $227,000, respectively, with a tax benefit of approximately

Table of Contents

$347,000 and $77,000, respectively, associated with our stock option grants.

The following table presents future stock-based compensation expense for our outstanding stock options which we expect to recognize during the indicated vesting periods:

	Future Compensation Expense *($ in thousands)*
Third quarter 2009	$ 352
Fourth quarter 2009	345
2010	999
2011	486
2012	159
2013	14
Total	$ 2,355

At June 30, 2009, options to purchase 397,750 shares of common stock were outstanding and vested. At that same date, options to purchase 805,450 shares were outstanding and unvested. During the six months ended June 30, 2009, options to purchase 464,200 shares were granted to officers and employees, and none of the options expired or were forfeited.

The fair value of each option award is estimated on the date of grant. The fair values of stock options granted prior to and outstanding at June 30, 2009 and that covered shares subject to future vesting at that date were determined using the Black-Scholes option valuation method from traded options and historical volatility of our stock. The expected term of the options used in the Black-Scholes model represents the period of time that options granted are expected to be outstanding. Risk free rates are based on the U.S. Treasury, Daily Treasury Yield Curve Rate.

	2009	2008	2005	2001
Expected volatility	63.94%	46.50%	54.20%	57.95%
Expected dividends	0.00	0.00	0.00	0.00
Expected term (in years)	6.25	6.25	6.5	7.5
Risk-free rate	3.19%	3.81%-3.86%	4.20%	5.05%

A summary of the stock option activity for the six months ended June 30, 2009 is presented below:

	Number of Shares of Common Stock Underlying Options *(in thousands)*	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term *(years)*	Aggregate Intrinsic Value *($ in thousands)*
Outstanding December 31, 2008	739	$ 14.41		
Granted	464	$ 2.00		
Exercised		$		
Surrendered		$		

Outstanding June 30, 2009	1,203	$	9.62	9.0	$
Exercisable at June 30, 2009	398	$	10.66	7.3	$

(8)

	($ in thousands)
Average weighted grant date fair value of options issued and unvested, June 30, 2009	$ 3,879
Average weighted grant date fair value of options issued and outstanding, June 30, 2009	$ 6,191

Restricted Stock

For the three months ended June 30, 2009 and 2008, we recognized compensation expense of approximately $21,000 and $57,000, with a tax benefit of approximately $7,000 and $19,000, respectively, for restricted stock. For the six months ended June 30, 2009 and 2008, we recognized compensation expense of approximately $45,000 and $57,000, respectively, with a tax benefit of approximately $15,000 and $19,000, respectively, for restricted stock.

The fair value of restricted stock awards granted are based on the last sales price of our common stock on the Nasdaq Global market on the date of the grant.

NOTE 3. CREDIT ARRANGEMENTS

We maintain one credit facility, our Fourth Amended and Restated Credit Agreement, or the Revolving Credit Agreement , dated May 16, 2008, as amended on April 30, 2009, which we describe below.

Revolving Credit Facility

Our Revolving Credit Agreement with a group of bank lenders provides us with a revolving line of credit having a borrowing base limitation of $230.0 million at June 30, 2009. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of $600.0 million or the borrowing base established by the lenders. At June 30, 2009, the principal amount outstanding under our revolving credit facility was $225.0 million, excluding $445,000 reserved for our letters of credit. The Revolving Credit Agreement allows us to borrow, repay and reborrow amounts available under the facility. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base is redetermined by the lenders semi-annually on or about April 1 and October 1 of each year or at other times required by the lenders or at our request. The April 30, 2009 amendment reaffirmed our borrowing base of $230.0 million and changed the funded debt ratio we are required to maintain as described below. If the outstanding principal amount of our loans ever exceeds the borrowing base, we must either provide additional collateral to the lenders or repay the outstanding principal of our loans in an amount equal to the excess. Except for principal payments that may be required because of our outstanding loans being in excess of the borrowing base, interest only is payable monthly.

As of June 30, 2009, our group of bank lenders included Citibank, N.A., BNP Paribas, Compass Bank, Bank of Scotland plc, Bank of America, N.A., Texas Capital Bank, N.A., Western National Bank and West Texas National Bank. None of the bank lenders held more than 21% of the facility at June 30, 2009.

Loans made to us under this revolving credit facility bear interest at the base rate of Citibank, N.A. or the LIBOR rate, at our election.

The base rate is generally equal to the sum of (a) Citibank s prime rate as announced by it from time to time plus (b) a margin ranging from zero to 0.50%, the amount of which depends upon the outstanding principal amount of our loan. If the principal amount outstanding is equal to or greater than 75% of the borrowing base, the margin is 0.50%. If the principal amount outstanding is equal to or greater than 50% but less than 75% of the borrowing base, the margin is 0.25%. If the borrowing base usage is less than 50%, there is no margin percent.

Table of Contents

The LIBOR rate is generally equal to the sum of (a) the rate designated as British Bankers Association Interest Settlement Rates and offered in one, two, three, six or twelve month interest periods for deposits of $1.0 million, and (b) a margin ranging from 2.75% to 3.25%, depending upon the outstanding principal amount of our loan. As amended on April 30, 2009, LIBOR margin means if the principal amount outstanding is equal to or greater than 75% of the borrowing base, the margin is 3.25%. If the principal amount outstanding is equal to or greater than 50%, but less than 75% of the borrowing base, the margin is 3.00%. If the principal amount outstanding is less than 50% of the borrowing base, the margin is 2.75%.

The interest rate we are required to pay on our borrowings, including the applicable margin, may never be less than 4.75%. At June 30, 2009, our base rate, plus the applicable margin, was 4.75% on $225.0 million, the outstanding principal amount of our revolving loan on that same date.

In the case of base rate loans, interest is payable on the last day of each month. In the case of LIBOR loans, interest is payable on the last day of each applicable interest period.

If the total outstanding borrowings under the revolving credit facility are less than the borrowing base, we are required to pay an unused commitment fee to the lenders in an amount equal to 0.25% of the daily average of the unadvanced portion of the borrowing base. The fee is payable quarterly.

If the borrowing base is increased, we are also required to pay a fee of 0.375% on the amount of any increase.

All outstanding principal and accrued and unpaid interest under the revolving credit facility is due and payable on December 31, 2013. The maturity date of our outstanding loans may be accelerated by the lenders upon the occurrence of an event of default under the Revolving Credit Agreement.

The Revolving Credit Agreement contains customary restrictive covenants, including (i) maintenance of a minimum current ratio, (ii) maintenance of a maximum ratio of funded indebtedness to earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), (iii) maintenance of a minimum net worth, (iv) prohibition of payment of dividends and (v) restrictions on incurrence of additional debt. As amended on April 30, 2009, our ratio of Consolidated Funded Debt to Consolidated EBITDA may not exceed 5.00 to 1.00 during 2009, 4.25 to 1.00 during 2010 or 4.00 to 1.00 during 2011 and thereafter.

We have pledged substantially all of our producing oil and natural gas properties to secure the repayment of our indebtedness under the revolving credit facility. If we breach any of the provisions of the credit agreement, including the financial covenants, and are unable to obtain waivers from our lenders, they would be entitled to declare an event of default, at which point the entire unpaid principal balance of the loans, together with all accrued and unpaid interest, would become immediately due and payable. Because substantially all of our assets are pledged as collateral under the revolving facility, if our lenders declare an event of default, they would be entitled to foreclose on and take possession of our assets.

In addition to the restrictive covenants contained in the Revolving Credit Agreement, our lenders have the unilateral authority to redetermine the borrowing base at any time they desire to do so. Any such unscheduled redetermination could result in the requirement for us to provide additional collateral or repay any borrowing base deficiency as described above. Although our lenders have not, in the past, initiated an unscheduled borrowing base determination, current economic conditions could cause the lenders to initiate such an unscheduled redetermination.

As of June 30, 2009 we were in compliance with the covenants in our Revolving Credit Agreement.

Senior Notes

At June 30, 2009, the carrying value of our $150.0 million $10^{1}/4$ % senior notes due 2014, or senior notes , was $146.2 million and their estimated fair value is approximately $104.3 million based on market trades at or near June 30, 2009. The senior notes mature on August 1, 2014 and bear interest at 10.25%, per annum on the principal amount. Interest is payable semi-annually on February 1 and August 1 of each year to holders of record at the close of business on the preceding January 15 and July 15, respectively, and payments commenced on February 1, 2008. Prior to August 1, 2010, we may redeem up to 35% of the senior notes for a price equal to 110.250% of the original principal amount of the senior notes with the proceeds of certain equity offerings. On or after August 1, 2011 we may redeem all or some of the senior notes at a redemption price that will decrease from 105.125% of the principal amount of the senior notes to 100% of the principal amount on August 1, 2013. In addition, prior to August 1, 2011, we may redeem some or all of the senior notes at a redemption price equal to 100% of the principal amount of the senior notes to be redeemed, plus a make-whole premium, plus any accrued and unpaid interest. Generally, the make-whole premium is an amount equal to the greater of (a) 1% of the principal amount of the senior notes being redeemed or (b) the excess of the present value of the redemption price of such notes as of August 1, 2011 plus all required interest payments due through August 1, 2011 (computed at a discount rate equal to a specified U.S. Treasury Rate plus 50 basis points), over the principal amount of the senior notes being redeemed. If we experience a change of control, we will be required to make an offer to repurchase the senior notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase.

The Indenture governing the senior notes restricts our ability to: (i) borrow money; (ii) issue redeemable and preferred stock; (iii) pay distributions or dividends; (iv) make investments; (v) create liens without securing the senior notes; (vi) enter into agreements that restrict dividends from subsidiaries; (vii) sell certain assets or merge with or into other companies; (viii) enter into transactions with affiliates; (ix) guarantee indebtedness; and (x) enter into new lines of business.

As of June 30, 2009 we were in compliance with the covenants in the Indenture.

Interest Incurred

For the six months ended June 30, 2009 and 2008, the aggregate interest incurred under our revolving credit facility and our senior notes was approximately $13.0 million and $10.3 million, respectively. Deferred financing costs and note discount amortization were approximately $588,000 and $621,000 and capitalized interest was approximately $1.0 million and $44,000 for the six months ended June 30, 2009 and 2008, respectively.

NOTE 4. OIL AND NATURAL GAS PROPERTIES

On February 11, 2009, we entered into a farmout agreement with Chesapeake Energy Corporation, or Chesapeake , related to our approximate 35% interest in the Barnett Shale gas project. Under the farmout agreement, for all wells drilled on our Barnett Shale leasehold from November 1, 2008 through December 31, 2016, we have agreed to assign to Chesapeake 100% of our leasehold in the Barnett Shale, subject to the following terms:

all wells drilled from November 1, 2008 through December 31, 2009, and all wells drilled during each succeeding calendar year through 2016 will be treated as a separate project or payout period, creating eight separate projects or payout periods;

at the time Chesapeake commences the drilling of a well during one of the payout periods, we will assign to Chesapeake 100% of our leasehold interest within the subject unit or lease, reserving and retaining a 50% reversionary interest that will vest after Chesapeake recovers 150% of its costs for a particular payout period. Until 150% payout has been reached, Chesapeake will fund 100% of our costs for drilling, completing and operating wells during the payout period;

on each project, Chesapeake is entitled to receive all revenues from our reversionary interest until Chesapeake receives revenues totaling 150% of the drilling, completion and operating costs Chesapeake incurs in funding our reversionary interest;

upon reaching the 150% payout level for a given project, 50% of the interest assigned to Chesapeake will revert back to us;

after 150% project payout, we will pay all costs and receive all revenues attributable to our 50% reversionary interest in each project;

for wells drilled after January 1, 2017, we will pay all costs and receive all revenues attributable to our 50% reversionary interest; and

we retained all of our interest in wells commenced prior to November 1, 2008, except for 3 wells commenced in late October 2008. We also retained all of our interest in approximately 90 gross (22.4 net) producing wells and 31 gross (9.49 net) wells in progress.

As non-operator, we do not control the timing of investment in the Barnett Shale gas project. For this reason, we entered into the farmout agreement. The farmout agreement had minimal effect on our proved reserves as of June 30, 2009 and December 31, 2008.

We estimate that our Barnett Shale leasehold acreage operated by Chesapeake and subject to the farmout agreement is approximately 25,600 gross (9,300 net) acres. We anticipate that approximately 61 gross (10.0 net) wells will be drilled and included in the 2009 payout period from November 1, 2008 through December 31, 2009. Payout of each project will depend on drilling and completion costs, timing of completion and pipeline connection to sales, and natural gas prices, among other things.

We use the full cost method to account for our oil and natural gas producing activities. Under the full cost method of accounting, the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed a calculated ceiling . The ceiling limitation is the discounted estimated after-tax future net cash flows from proved oil and natural gas properties. The net book value of oil and natural gas properties, less related deferred income taxes, is compared to the ceiling on a quarterly and annual basis. Any excess of the net book value, less related deferred income taxes, is generally written off as an expense.

Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of oil and natural gas properties, including a portion of our overhead, are capitalized. In the six months ended June 30, 2009 and 2008, overhead costs capitalized were approximately $680,000 and $842,000, respectively.

We have recognized an impairment of approximately $30.4 million during the six months ended June 30, 2009. We did not recognize an impairment in the quarter ended June 30, 2009 or in the six months ended June 30, 2008. We cannot assure you that we will not experience further impairments in the future.

Table of Contents

The following table reflects capitalized costs related to the oil and natural gas properties as of June 30, 2009 and December 31, 2008.

	June 30, 2009	December 31, 2008
	($ in thousands)	
Proved properties	$ 752,630	$ 741,520
Unproved properties, not subject to depletion	136,046	137,202
	888,676	878,722
Accumulated depletion (1)	(530,596)	(488,168)
	$ 358,080	$ 390,554

(1) Includes $30.4 million and $300.5 million impairment of oil and natural gas properties for the periods ending June 30, 2009 and December 31, 2008, respectively.

NOTE 5. OTHER ASSETS

Below are the components of other assets as of June 30, 2009 and December 31, 2008.

	June 30, 2009	December 31, 2008
	($ in thousands)	
Revolving credit facility deferred financing costs, net	$ 1,813	$ 1,306
Senior notes deferred financing costs, net	1,304	1,432
Other	195	828
	$ 3,312	$ 3,566

NOTE 6. OTHER ACCRUED LIABILITIES

Below are the components of other accrued liabilities as of June 30, 2009 and December 31, 2008.

June 30,

	2009	December 31, 2008
	($ in thousands)	
Revenue payable to joint interest and royalty owners	$ 6,675	$ 8,004
Accrued capital expenditures	1,566	9,275
Accrued lease operating expense	1,856	2,223
Accrued ad valorem taxes	2,038	150
Other	2,288	2,128
	$ 14,423	$ 21,780

(13)

Table of Contents

NOTE 7. ASSET RETIREMENT OBLIGATIONS

The following table summarizes our asset retirement obligation transactions for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	($ in thousands)		*($ in thousands)*	
Beginning asset retirement obligation	$ 11,429	$ 5,802	$ 11,379	$ 4,937
Additions related to new properties	6	554	121	706
Revisions in estimated cash flows	(1,643)	(851)	(1,715)	(209)
Deletions related to property disposals	(3)	(3)	(206)	(15)
Accretion expense	215	104	425	187
Ending asset retirement obligation	$ 10,004	$ 5,606	$ 10,004	$ 5,606

The adoption of FAS 157 on non-financial assets and liabilities related to our asset retirement obligations had an immaterial impact on our balance sheet as of June 30, 2009 and our results of operations for the three and six months ended June 30, 2009. Our asset retirement obligation is measured using primarily Level 3 inputs. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs and well life. The inputs are calculated based on historical data as well as current estimated costs.

NOTE 8. DERIVATIVE INSTRUMENTS

General

We enter into derivative contracts to provide a measure of stability in the cash flows associated with our oil and natural gas production and interest rate payments and to manage exposure to commodity price volatility and interest rate risk. Our objective is to lock in a range of oil and natural gas prices and to limit variability in our cash interest payments. In addition, our revolving credit facility requires us to maintain derivative financial instruments which limit our exposure to fluctuating commodity prices covering at least 50% of our estimated monthly production of oil and natural gas extending 24 months into the future.

Our put contracts contain a financing element, which management believes is other than insignificant, resulting in related cash settlements being classified as cash from financing activities within the Statement of Cash Flows. These settlements are disclosed as net settlements to reflect the amount of the gross settlement less the amount of the original put premium for the specific contracts being settled.

All derivative contracts are marked to market at each period end and the increases or decreases in fair values recorded to earnings.

We are exposed to credit risk in the event of nonperformance by the counterparties to these contracts, BNP Paribas and Citibank, N.A. We actively monitor our credit risks related to financial institutions and counterparties including monitoring credit agency ratings, financial position and current news to mitigate this credit risk. We minimize credit risk in derivative instruments by entering into transactions with counterparties that are parties to our credit facility. See Item 1A. Risk Factors for additional discussion concerning the risk with counterparties of the derivative instruments.

Adoption of SFAS No. 161

We adopted SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS 161), effective January 1, 2009 for all financial assets and liabilities. SFAS 161 requires enhanced disclosures about an entity s derivative and hedging activities and thereby improves transparency of financial reporting. Entities are required to provide enhanced disclosure 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 flow.

The tables below provide the fair values of the derivative instruments and their gains and losses located on the Balance Sheet and Statement of Operations as of June 30, 2009.

Fair Values of Derivative Instruments on the Balance Sheet
Derivatives not Designated as Hedging Instruments under Statement 133

	As of June 30, 2009	As of December 31, 2008
	($ in thousands)	
Derivative Asset		
Gas swaps	$ 210	$
Gas collars	5,418	6,611
Oil collars	1,660	13,480
Oil puts	10,153	16,655
Derviative Obligation		
Interest rate swaps	(6,616)	(8,051)
Gas collars	(1,475)	
Oil collars	(1,687)	(89)
Net derivative asset	$ 7,663	$ 28,606

The Effect of Derivative Instruments on the Statement of Operations
Derivatives not Designated as Hedging Instruments under Statement 133(1)

	For the three months ended June 30, 2009	For the three months ended June 30, 2008	For the six months ended June 30, 2009	For the six months ended June 30, 2008
	($ in thousands)		*($ in thousands)*	
Interest rate swaps	$ 457	$ 1,407	$ (23)	$ (695)
Gas collars	(1,040)	(9,147)	3,482	(13,712)
Gas swaps	175		537	
Oil swaps		(11,847)		(14,886)
Oil collars	(8,983)	(51,597)	(7,652)	(63,777)
Oil puts	(3,895)	(425)	(3,865)	(425)
Total loss on derivatives	$ (13,286)	$ (71,609)	$ (7,521)	$ (93,495)

(1)

All changes in the mark-to-market valuation of our derivatives are recorded on the Statement of Operations under the line item Loss on derivatives not classified as hedges .

(15)

Table of Contents

Adoption of SFAS No. 157

We adopted SFAS No. 157, *Fair Value Measurements* (SFAS 157), effective January 1, 2008 for all financial assets and liabilities. Beginning January 1, 2009, we also applied SFAS No. 157 to non-financial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). In determining the fair value of its derivative contracts the Company evaluates its counterparty and third party service provider valuations and adjusts for credit risk when appropriate. We use historical prices for volatility assumptions, future market prices and treasury rates as inputs to value the oil, natural gas and interest rate derivatives. SFAS 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires that fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps and interest rate swaps.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our valuation models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 3 instruments primarily include derivative instruments, such as commodity price collars and puts. These instruments are considered Level 3 because we do not have sufficient corroborating market evidence for volatility to support classifying these assets and liabilities as Level 2.

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Table of Contents

The following table summarizes the valuation of our derivative financial assets (liabilities) by SFAS No. 157 valuation levels as of June 30, 2009 (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value at June 30, 2009
Interest swaps	$	$ (6,616)	$	$ (6,616)
Gas swaps	$	$ 210	$	$ 210
Oil puts	$	$	$ 10,153	$ 10,153
Oil & gas collars	$	$	$ 3,916	$ 3,916
	$	$ (6,406)	$ 14,069	$ 7,663

The determination of the fair values above incorporates various factors required under SFAS No. 157. These factors include the impact of our nonperformance risk and the credit standing of the counterparties involved in our derivative contracts. The risk of nonperformance by our counterparties is mitigated by the fact that such counterparties (or their affiliates) are also bank lenders under our Revolving Credit Agreement and the derivative instruments with these counterparties allow us to setoff amounts owed by the counterparty to it against any obligation we owe the counterparty under our Revolving Credit Agreement.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy (in thousands).

	Three Months Ended June 30, 2009		Six Months Ended June 30, 2009	
	Derivative Collars	Derivative Puts	Derivative Collars	Derivative Puts
Beginning balance	$ 18,887	$ 15,160	$ 20,002	$ 16,656
Total losses	(10,024)	(3,904)	(4,170)	(3,867)
Settlements[1]	(4,947)	(1,103)	(11,916)	(2,636)
Purchases				
Transfers in and/or out of level 3				
Balance at end of period	$ 3,916	$ 10,153	$ 3,916	$ 10,153
Change in unrealized losses included in earnings relating to derivatives still held as of June 30, 2009[2]	$ (14,971)	$ (5,007)	$ (16,086)	(6,503)

(1) Put premiums were netted from the settlement receipts of

$161,000 for the three months ended June 30, 2009 and $320,000 for the six months ended June 30, 2009.

(2) Losses (realized and unrealized) are included in earnings and are reported in Loss on derivatives not classified as hedges in the Statement of Operations.

During periods of market disruption, including periods of volatile oil and gas prices, rapid credit contraction or illiquidity, it may be difficult to value certain of our derivative instruments if trading becomes less frequent and/or market data becomes less observable. There may be certain asset classes that were in active markets with observable data that become illiquid due to the current financial environment. In such cases, more derivative instruments may fall to Level 3 and thus require more subjectivity and management judgment. As such, valuations may include inputs and assumptions that are less observable or require greater estimation as well as valuation methods which are more sophisticated or require greater estimation thereby resulting in valuations with less certainty. Further, rapidly changing and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition.

Interest Rate Sensitivity

We have entered into interest rate swap contracts with BNP Paribas and Citibank, N.A. (the counterparties) which are intended to have the effect of converting variable rate interest payments required to be made on our Revolving Credit Agreement to fixed interest rates for the periods covered by the swaps. Under terms of these swap contracts, in periods during which the fixed interest rate stated in the swap contract exceeds the variable rate (which is based on a 90-day LIBOR rate) we pay to the counterparties an amount determined by applying this excess fixed rate to the notional amount of the contract. In periods when the variable rate exceeds the fixed rate stated in the swap contracts, the counterparties pay an amount to us determined by applying the excess of the variable rate over the stated fixed rate to the notional amount of the contract. These contracts are accounted for by mark-to-market accounting as prescribed in SFAS 133. We have historically viewed these contracts as additional protection against future interest rate volatility. As of June 30, 2009, the fair market value of these interest rate swaps was a liability of approximately $6.6 million.

The table below recaps the terms of these interest rate swaps and the fair market value of these contracts as of June 30, 2009.

Period of Time	Notional Amounts	Weighted Average Fixed Interest Rates	Estimated Fair Market Value
	($ in millions)		*($ in thousands)*
July 1, 2009 through December 31, 2009	$ 100	4.22%	$ (1,798)
January 1, 2010 through October 31, 2010	$ 100	4.71%	(2,777)
November 1, 2010 through December 31, 2010	$ 50	4.26%	(237)
January 1, 2011 through December 31, 2011	$ 100	4.67%	(1,804)
Total Fair Market Value			$ (6,616)

Commodity Price Sensitivity

All of our commodity derivatives are accounted for using mark-to-market accounting as prescribed in SFAS 133.

Put Options. Puts are options to sell an asset at a specified price. For any put transaction, the counterparty is required to make a payment to the Company if the reference floating price for any settlement period is less than the put or floor price for such contract.

In June 2008, we entered into multiple put contracts with BNP Paribas and in October 2008 we entered into a put contract with Citibank, N.A. In lieu of making premium payments for the puts at the time of entering into our put contracts, we deferred payment until the settlement dates of the contracts. Future premium payments will be netted against any payments that the counterparty may owe to us based on the floating price. Due to the deferral of the premium payments, we will pay a total amount of premiums of $4.68 million which is $491,000 greater than if the premiums had been paid at the time of entering into the contracts. The $491,000 difference is recorded as a discount to the put premium obligations and recognized as interest expense over the terms of the contracts using the effective interest method. Through June 30, 2009, we had accrued approximately $183,000 of interest expense and settled premiums of approximately $320,000. Accordingly, the recorded balance of the put premium obligations at June 30, 2009 is approximately $4.1 million.

Table of Contents

A summary of our put positions at June 30, 2009 is as follows:

Period of Time	Barrels of Oil	Floor	Estimated Fair Market Value *($ in thousands)*
July 1, 2009 through December 31, 2009	55,200	$ 100.00	$ 1,575
January 1, 2010 through December 31, 2010	280,100	$ 84.36	4,709
January 1, 2011 through December 31, 2011	146,000	$ 100.00	3,869
Total Fair Market Value			$ 10,153

Collars. Collars are contracts which combine both a put option or floor and a call option or ceiling . These contracts may or may not involve payment or receipt of cash at inception, depending on the ceiling and floor pricing.

On April 8, 2009, we executed a natural gas costless collar trade for 2,000 MMBtu/day (WAHA) for calendar year 2010 with a floor of $4.70 and a ceiling of $5.65 with a total volume of 730,000 MMBtu. We also executed a second natural gas costless collar trade for 5,000 MMBtu/day (WAHA) for the three months of October, November and December 2009 with a floor of $3.60 and a ceiling of $4.10 with a total volume of 460,000 MMBtu.

On June 15, 2009, we executed an oil costless collar trade for 700 Bbl/day oil (WTI-NYMEX) for calendar year 2011 with a floor of $70.00 and a ceiling of $94.25 with a total volume of 255,500 Bbl. We also executed a second oil costless collar trade for 1,000 Bbl/day oil (WTI-NYMEX) for calendar 2012 with a floor of $70.00 and a ceiling of $101.50 with a total volume of 366,000 Bbl.

A summary of our collar positions at June 30, 2009 is as follows:

Period of Time	Barrels of Oil	NYMEX Oil Prices Floor	NYMEX Oil Prices Ceiling	Estimated Fair Market Value *($ in thousands)*
July 1, 2009 through December 31, 2009	386,400	$65.71	$ 82.93	$ 417
January 1, 2010 through October 31, 2010	486,400	$63.44	$ 78.26	(1,503)
January 1, 2011 through December 31, 2011	255,500	$70.00	$ 94.50	424
January 1, 2012 through December 31, 2012	366,000	$70.00	$101.50	634
	MMBtu of Natural Gas	WAHA Gas Prices Floor	WAHA Gas Prices Ceiling	
July 1, 2009 through December 31, 2009	2,116,000	$ 6.30	$ 8.66	5,246
January 1, 2010 through December 31, 2010	4,380,000	$ 4.74	$ 5.86	(1,302)
Total Fair Market Value				$ 3,916

Commodity Swaps. Generally, swaps are an agreement to buy or sell a specified commodity for delivery in the future, at an agreed fixed price. Swap transactions convert a floating or market price into a fixed price. For any particular swap transaction, the counterparty is required to make a payment to the Company if the reference price for any settlement period is less than the swap or fixed price for such contract, and the Company is required to make a payment to the counterparty if the reference price for any settlement period is greater than the swap or fixed price for such contract.

A recap for the period of time, MMBtu quantities and swap prices are as follows:

Period of Time	MMBtu of Natural Gas	WAHA Swap Price	Estimated Fair Market Value *($ in thousands)*
July 1, 2009 through September 30, 2009	460,000	$ 3.91	$ 210

NOTE 9. NET LOSS PER COMMON SHARE

Basic earnings per share (EPS) exclude any dilutive effects of options, warrants and convertible securities and is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share are computed similar to basic earnings per share. However, diluted earnings per share reflect the assumed conversion of all potentially dilutive securities.

The following table provides the computation of basic and diluted loss per share for the three and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands, except per share data)			
Basic EPS Computation:				
Numerator-				
Net loss	$ (9,640)	$ (29,205)	$ (30,001)	$ (31,945)
Denominator-				
Weighted average common shares outstanding	41,597	41,446	41,597	41,359
Basic EPS:				
Net loss per share	$ (0.23)	$ (0.70)	$ (0.72)	$ (0.77)
Diluted EPS Computation:				
Numerator-				
Net loss	$ (9,640)	$ (29,205)	$ (30,001)	$ (31,945)
Denominator-				
Weighted average common shares outstanding	41,597	41,446	41,597	41,359
Employee stock options				
Warrants				
Weighted average common shares for diluted earnings per share assuming conversion	41,597	41,446	41,597	41,359

Diluted EPS:				
Net loss per share	$ (0.23)	$ (0.70)	$ (0.72)	$ (0.77)

For the three and six months ended June 30, 2009 and 2008, the effects of all potentially dilutive securities (including options and warrants) were excluded from the computation of diluted earnings per share because we had a net loss and, therefore, the effect would have been anti-dilutive. There were no options excluded from the computation of diluted earnings per share for the three months ended June 30, 2009. For the three months ended June 30, 2008, options and warrants to purchase 370,000 shares of common stock were excluded from the computation of diluted earnings per share. There were no options excluded from the computation of diluted earnings per share for the six months ended June 30, 2009. For the six months ended June 30, 2008, options and warrants to purchase 429,000 shares of common stock were excluded from the computation of diluted earnings per share.

NOTE 10. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations,* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be the Company s fiscal year 2009. The adoption of SFAS 141(R) effective January 1, 2009 has had no effect on our financial position or results of operations as we have made no acquisitions during the six months ended June 30, 2009. However, the impact, if any, will depend on the nature and size of business combinations we consummate thereafter.

In February 2008, the FASB issued Staff Position No. 157-2, *Effective Date of FASB Statement No. 157* (FSP 157-2), which granted a one-year deferral of the effective date of SFAS No. 157 as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and asset retirement obligations). Beginning January 1, 2009, we applied SFAS No. 157 to non-financial assets and liabilities. The adoption of SFAS No. 157 did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* (SFAS 161). This statement is intended to improve transparency in financial reporting by requiring enhanced disclosures of an entity s derivative instruments and hedging activities and their effects on the entity s financial position, financial performance, and cash flows. SFAS 161 applies to all derivative instruments within the scope of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities,* (SFAS 133), as well as related hedged items, bifurcated derivatives, and nonderivative instruments that are designated and qualify as hedging instruments. Entities with instruments subject to SFAS 161 must provide expanded disclosures. SFAS 161 is effective prospectively for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application permitted. We applied SFAS 161 beginning January 1, 2009. The adoption of SFAS No. 161 has not had an impact on our financial position or results of operations.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles,* (SFAS 162), which becomes effective for the Company 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With General Accepted Accounting Principles*. This standard identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements that are presented in conformity with generally accepted accounting principles. We do not anticipate that this pronouncement will have a material impact on our results of operations or financial position.

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting.* The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations.

The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. The Company has not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices, on its disclosures, financial position or results of operations.

In April 2009, the FASB issued FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP 107-1). FSP 107-1 amends FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments,* to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This FSP also amends APB Opinion No. 28, *Interim Financial Reporting,* to require those disclosures in summarized financial information at interim reporting periods. This FSP shall be effective for interim reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. An entity may early adopt this FSP only if it also elects to early adopt FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* and FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*. This FSP does not require disclosures for earlier periods presented for comparative purposes at initial adoption. In periods after initial adoption, this FSP requires comparative disclosures only for periods ending after initial adoption. We do not anticipate that this pronouncement will have a material impact on our results of operations or financial position.

In April 2009, the FASB issued FASB Staff Position FAS 141-(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies* (FSP 141-(R)-1). FSP 141-(R)-1 amends and clarifies FASB Statement No. 141 (revised 2007), *Business Combinations* to address application issues raised by preparers, auditors, and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP shall be effective for assets or liabilities arising from contingencies in 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. The impact, if any, will depend on the nature and terms of business combinations we consummate after the effective date.

In May 2009, the FASB issued SFAS No. 165*, Subsequent Events* (SFAS 165), which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In particular, this Statement sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. This Statement shall be effective for interim or annual financial periods ending after June 15, 2009, and shall be applied prospectively. We adopted SFAS 165 beginning June 30, 2009 and the adoption did not have a material impact on our financial position or results of operations. The date through which subsequent events have been evaluated is August 4, 2009, the date on which we filed our Form 10-Q with the Securities and Exchange Commission.

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification*

TM and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162 (SFAS 168) which establishes the *FASB Accounting Standards Codification* TM (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. This Statement shall be effective for financial statements issued for interim and annual periods ending after September 15, 2009. On the effective date of this Statement, all then-existing non-SEC accounting and reporting standards are superseded, except as noted within the SFAS 168. Concurrently, all nongrandfathered, non-SEC accounting literature not included in the Codification is deemed non-authoritative with some exceptions as noted within the literature. We do not anticipate that this pronouncement will have a material impact on our results of operations or financial position.

NOTE 11. COMMITMENTS AND CONTINGENCIES

From time to time, we are party to ordinary routine litigation incidental to our business.

On March 24, 2008, a lawsuit was filed in the 24th District Court of Jackson County, Texas, against us and twenty-two other defendants in Cause No. 07-6-13069, styled Tony Kubenka, Carolyn Kubenka, Dennis J. Kallus, David J. Kallus, Mary L. Kallus, Patricia Kallus, Nova Deleon, Janie Figuerova, and Larkin Thedford, Plaintiffs v. Tri-C Resources, Inc., Marie S. Adian, Laura E. Adian, Glenn A. Fiew, Lynn Kramer, Debra Boysen, Carol J. Gleason, Alana Sue Curlee, Connie W. Marthiljohni, Claire E. Adian, Zachary D. Adian, Donald R. Starkweather, Inc., D.A. Webernick, Danette Bundick, Johnny A. Webernick, Donna Gail Glover, Sherry Shulze, William H. Webernick, Jr., TAC Resources, Inc., New Century Exploration, Inc., Allegro Investments, Inc., Parallel Petroleum Corporation and Welper Interests, LP . The nine plaintiffs in this lawsuit have named us and the other working interest owners, including Tri-C Resources, Inc., the operator, as defendants. The plaintiffs in this lawsuit allege that they are royalty owners under oil and gas leases which are part of a pooled gas unit (the unit) located in Jackson County, Texas, and that the defendants, including us, are owners of the leasehold estate under the plaintiffs leases and others forming the unit. Plaintiffs also assert that one of the leases (other than plaintiffs leases) forming part of the unit has been terminated and, as a result, the defendants have not properly computed the royalties due to plaintiffs from unit production and have failed to properly pay royalties due to them. Plaintiffs have sued for an unspecified amount of damages, including exemplary damages, under theories of breach of contract (including breach of express and implied covenants of their leases) and conversion, and seek an accounting, a declaratory judgment to declare the rights of the parties under the leases, and attorneys fees, interest and court costs. If a judgment adverse to the defendants were entered, as a working interest owner in the leases comprising the unit, we believe our liability would be proportionate to the ownership of the other working interest owners in the leases. We have filed an answer denying any liability. Although an initial exchange of discovery has occurred, we cannot predict the ultimate outcome of this matter, but believe we have meritorious defenses and intend to vigorously contest this lawsuit. We have not established a reserve with respect to plaintiffs claims.

We received a Notice of Proposed Adjustment from the Internal Revenue Service, or the Service in May 2007 advising us of proposed adjustments to federal income tax of approximately $2.0 million for the years 2004 and 2005. Subsequent discussions with the Service placed the issues contested in a development status. In November 2007, the Service issued a letter on the matter giving us 30 days to agree or disagree with a final examination report. The final examination report reflected revisions of the previous proposed adjustments resulting in a reduced $1.1 million of additional income tax and interest charges. The decrease in proposed tax was the result of information supplied by us to the examiner as well as discussions of the applicable tax statutes and regulations. In December 2007, we filed a protest documenting our complete disagreement with the adjustments proposed on the final examination report and requested a conference with the appeals office of the Service. The examination office of the Service

Table of Contents

filed a response to our protest in February 2008 with the appeals office. In the response the additional tax was further reduced by the examination office to $720,000. In June and November of 2008, our representatives met with the Service s Appeals Officer to review specific issues related to the alternative minimum tax items in dispute. During these meetings we submitted supplements to our initial protest in further support of our position. On May 27, 2009 we received a written proposal from the Service under which we would not owe any additional taxes or interest for the years 2004 and 2005, but which would require us to reduce future alternative minimum tax net operating losses by approximately $18.6 million. We have accepted this offer and are awaiting final notification from the Service that this matter is closed. This reduction has no direct impact on our earnings, but could accelerate the timing of future tax payments.

We also are presently a named defendant in one other lawsuit arising out of our operations in the normal course of business, which we believe is not material.

We are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statues to which we are subject, nor have we been a party to any bankruptcy, receivership, reorganization, adjustment or similar proceedings.

Effective January 1, 2005, we established a 401(k) Plan and Trust for eligible employees. For the three months ended June 30, 2009 and 2008, we made contributions to the 401(k) Plan and Trust of approximately $85,000 and $77,000, respectively. For the six months ended June 30, 2009 and 2008, we made contributions to the 401(k) Plan and Trust of approximately $172,000 and $152,000, respectively.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion and analysis should be read in conjunction with management s discussion and analysis contained in our 2008 Annual Report on Form 10-K, as well as the unaudited financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

OVERVIEW

Strategy

2009 Priorities. Due to the current economic environment, we have identified four areas in which we will concentrate our efforts in 2009. These areas of concentration are dependent on market conditions and some could change as prices and events in 2009 develop. At present, our four top priorities for 2009 are:

- maximize liquidity and financial flexibility;
- generate operating cash flow in excess of our capital investment budget (CAPEX);
- invest $29.1 million in CAPEX spending; and
- focus on operated properties.

As described in Note 4- Oil and Natural Gas Properties , we entered into a farmout agreement with Chesapeake Energy Corporation which will allow us to conserve cash and more importantly direct efforts in areas in which we believe have a greater rate of return for the Company. The majority of the remaining planned CAPEX spending for 2009 will be on our operated properties where we can control the timing and pace of this spending. If prices continue to deteriorate, we will be able to defer planned spending until prices increase and/or service costs decrease to support these projects. Under our current budget and with existing prices, we anticipate that all spending will be supported by operating cash flow generated by our expected production and by settlements of our derivative contracts. However, if we determine that operating cash flow and derivative settlements will not support our spending, we will be able to alter our budget so that we retain our financial and operational flexibility in the existing adverse market environment.

Conduct Exploitation Activities on Our Existing Assets. We seek to maximize economic return on our existing assets by maximizing production rates and ultimate recovery, while managing operational efficiency to minimize direct lifting costs. Development and production growth activities include infill and extension drilling of new wells, re-completion, pay adds and re-stimulation of existing wells and implementation and management of enhanced oil recovery projects such as waterflood operations. Operational efficiencies and cost reduction measures include optimization of surface facilities, such as fluid handling systems, gas compression or artificial lift installations. Efficiencies are also increased through aggressive monitoring and management of electrical power consumption, injection water quality programs, chemical and corrosion prevention programs and the use of production surveillance equipment and software. In all instances, a proactive approach is taken to achieve the desired result while ensuring minimal environmental impact.

Use of Horizontal Drilling and Fracture Stimulation Activities in Gas Resource Plays. We believe the use of horizontal drilling and fracture stimulations has enabled us to develop reserves economically, such as our Barnett Shale and Wolfcamp Carbonate gas projects. We also believe our expertise in utilizing this technology will create additional opportunities in our current projects as well as future opportunities in other resource plays. While we believe we can find oil and natural gas reserves more effectively using this technology, under the current economic environment, our capital resources can be better utilized elsewhere. We will continue to use this technology as natural gas prices and overall market conditions dictate.

Use of Advanced Technologies and Production Techniques. We believe that 3-D seismic surveys, horizontal drilling, fracture stimulation and other advanced technologies and production techniques are useful tools that help improve normal drilling operations and enhance our production and returns. We believe that our use of these technologies and production techniques in exploring for, developing and exploiting oil and natural gas properties can reduce drilling risks, lower finding costs, provide for more efficient production of oil and natural gas from our properties and increase the probability of locating and producing reserves that might not otherwise be discovered.

Acquire Long-Lived Properties with Enhancement Opportunities. Our acquisition strategy is focused on leveraging our geographical expertise in our core areas of operation and seeking assets located in and around these areas. We selectively evaluate acquisition opportunities and expect that they will continue to play a role in increasing our reserve base and future drilling inventory. When identifying target assets, we focus primarily on reserve quality and assets in new development plays with upside potential. Through this approach, we have traditionally targeted smaller asset acquisitions which allow us to absorb, enhance and exploit properties without taking on significant integration risk. While we have not adopted any specific quantitative guidelines for the screening of prospective leasehold or producing property acquisitions, desirable attributes related to reserve life include a reserve to production ratio of greater than 15 years and stabilized exponential decline rates of less than 20% per year. We believe these types of properties provide us with a greater certainty in growing production, reserves and shareholder value through time.

Conduct Exploratory Activities. Although we do not emphasize exploratory drilling, we will selectively undertake exploratory projects that have known geological and reservoir characteristics that are in close proximity to existing wells so data from the existing wells can be correlated with seismic data on or near the prospect being evaluated, and that could have a potentially meaningful impact on our reserves.

The extent to which we are able to implement and follow through with our business strategy is influenced by:

- the prices we receive for the oil and natural gas we produce;
- sources and availability of funds to conduct operations and complete acquisitions;
- the results of reprocessing and reinterpreting our 3-D seismic data;
- the results of our drilling activities;
- the costs of obtaining high quality field services;
- our ability to find and consummate acquisition opportunities; and
- our ability to negotiate and enter into work to earn arrangements, joint ventures or other similar arrangements on terms acceptable to us.

Significant changes in the prices we receive for the oil and natural gas we produce, or the occurrence of unanticipated events beyond our control, such as the recent and dramatic downturn in the financial markets, can cause us to defer or deviate from our business strategy, including the amounts we have budgeted for our activities. See -Trends and Outlook below.

Operating Performance

Our operating performance is influenced by several factors, the most significant of which are the prices we receive for our oil and natural gas and the quantities of oil and natural gas that we are able to produce. The world price for oil has overall influence on the prices that we receive for our oil production. The prices received for different grades of oil are based upon the world price for oil, which is then adjusted based upon the particular grade. Typically, light oil is sold at a premium, while heavy grades of crude are discounted. Natural gas prices we receive are influenced by:

- seasonal demand;
- weather;
- hurricane conditions in the Gulf of Mexico;
- availability of pipeline transportation to end users;
- proximity of our wells to major transportation pipeline infrastructures; and
- to a lesser extent, world oil prices.

Additional factors influencing our overall operating performance include:

- production expenses;
- overhead requirements;
- costs of capital; and
- effects of derivative contracts.

Our oil and natural gas exploration, development and acquisition activities require substantial and continuing capital expenditures. Historically, the sources of financing to fund our capital expenditures have included:

Table of Contents

- cash flow from operations;
- sales of our equity and debt securities;
- bank borrowings; and
- industry joint ventures.

Overall, decreases in the average sales price of crude oil and natural gas is the most significant factor affecting operating performance. Our average price received for crude oil during the three months ended June 30, 2009 (the Current Quarter) was $55.57/Bbl versus $119.42/Bbl in the three months ended June 30, 2008 (the Comparable Quarter). Our average price received for natural gas in the Current Quarter was $2.78/Mcf versus $9.95/Mcf for the Comparable Quarter. Oil and natural gas sales revenue is down 65% when comparing the Current Quarter to the Comparable Quarter. The reduction in pricing accounts for approximately 87% of this reduction while volume decreases accounted for the remaining 13%. During the same time, operating costs and expenses were down 38%. A substantial portion of this reduction was due to a decrease in our depreciation, depletion and amortization costs. This was a direct result of our impairments which we incurred at year end 2008 and at the end of the prior quarter. For more information regarding prices received and operating results, you should refer to the selected operating data table under -Results of Operations on page 28.

Our average price received for crude oil during the six months ended June 30, 2009 (the Current Period) was $45.79/Bbl versus $106.32/Bbl in the six months ended June 30, 2008 (the Comparable Period). Our average price received for natural gas in the Current Period was $3.21/Mcf versus $8.90/Mcf for the Comparable Period. Oil and natural gas sales revenue was down 62% when comparing the Current Period to the Comparable Period. The reduction in pricing accounts for approximately 92% of this reduction while volume decreases accounted for just 8%. During the same time, operating costs and expenses were down 25%, excluding the impact of the $30.4 million impairment write down we made in the quarter ended March 31, 2009. A substantial portion of this reduction was due to a decrease in our depreciation, depletion and amortization costs. This was a direct result of our impairments which we incurred at year end 2008 and at the end of the prior quarter. For more information regarding prices received and operating results, you should refer to the selected operating data table under -Results of Operations on page 28.

Our oil and natural gas producing activities are accounted for using the full cost method of accounting. Under this accounting method, we capitalize all costs incurred in connection with the acquisition of oil and natural gas properties and the exploration for and development of oil and natural gas reserves. These costs include lease acquisition costs, geological and geophysical expenditures, costs of drilling productive and non-productive wells, and overhead expenses directly related to land and property acquisition and exploration and development activities. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction in capitalized costs, with no gain or loss recognized unless a disposition involves a material change in the relationship between capitalized costs and reserves, in which case the gain or loss is recognized. Please see Note 4- Oil and Natural Gas Properties for a discussion on the impairment calculation.

Depletion of the capitalized costs of oil and natural gas properties, including estimated future development costs, is provided using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves and production, which are converted to a common unit of measure based upon their relative energy content. Unproved oil and natural gas properties are not amortized, but are individually assessed for impairment. The cost of any impaired property is transferred to the balance of oil and natural gas properties being depleted.

Table of Contents

Results of Operations

Our business activities are characterized by frequent, and sometimes significant, changes in our:

- reserve base;
- sources of production;
- product mix (gas versus oil volumes); and
- the prices we receive for our oil and natural gas production.

Year-to-year or other periodic comparisons of the results of our operations can be difficult and may not fully and accurately describe our condition.

The following table shows selected operating data for each of the three and six months ended June 30, 2009 and June 30, 2008.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands, except per unit data)			
Production Volumes:				
Oil (Bbls)	248	237	500	484
Natural gas (Mcf)	2,196	2,790	4,725	5,452
BOE(1)	614	702	1,288	1,393
BOE per day	6.7	7.7	7.1	7.7
Sales Prices:				
Oil (per Bbl)	$ 55.57	$ 119.42	$ 45.79	$ 106.32
Natural gas (per Mcf)	$ 2.78	$ 9.95	$ 3.21	$ 8.90
BOE price	$ 32.37	$ 79.86	$ 29.58	$ 71.80
Operating Revenues:				
Oil	$ 13,758	$ 28,322	$ 22,905	$ 51,491
Natural gas	6,103	27,753	15,185	48,525
	$ 19,861	$ 56,075	$ 38,090	$ 100,016
Operating Expenses:				
Lease operating expense	$ 5,541	$ 7,254	$ 13,627	$ 14,233
Production taxes	761	2,996	1,334	5,285
General and administrative	3,281	3,265	6,714	5,833
Depreciation, depletion and amortization	5,398	10,483	12,179	19,835
Impairment of oil and natural gas properties			30,426	
	$ 14,981	$ 23,998	$ 64,280	$ 45,186
Operating income (loss)	$ 4,880	$ 32,077	$ (26,190)	$ 54,830

(1) A BOE means one barrel of oil equivalent using the ratio of six Mcf of gas to one barrel of oil.

Table of Contents

RESULTS OF OPERATIONS

For the Three Months Ended June 30, 2009 and 2008:

Percentages of our oil and natural gas revenues and production, by product, are displayed in the following table for the Current Quarter and Comparable Quarter.

Oil and Gas Revenues

	Revenues For the Three Months Ended June 30,		Production For the Three Months Ended June 30,	
	2009	2008	2009	2008
Oil (Bbls)	69%	51%	40%	34%
Natural gas (Mcf)	31%	49%	60%	66%
Total	100%	100%	100%	100%

The following table shows our production volumes, product sales prices and operating revenues for the indicated periods.

	Three Months Ended June 30, 2009	2008	Change	Percentage Change
	(in thousands except per unit data)			
Production Volumes:				
Oil (Bbls)	248	237	11	5%
Natural gas (Mcf)	2,196	2,790	(594)	(21)%
BOE (1)	614	702	(88)	(13)%
BOE/Day	6.7	7.7	(1.0)	(13)%
Sales Price:				
Oil (per Bbl)	$ 55.57	$ 119.42	$ (63.85)	(53)%
Natural gas (per Mcf)	$ 2.78	$ 9.95	$ (7.17)	(72)%
BOE price	$ 32.37	$ 79.86	$ (47.49)	(59)%
Operating Revenues:				
Oil	$ 13,758	$ 28,322	$ (14,564)	(51)%
Natural gas	6,103	27,753	(21,650)	(78)%
Total	$ 19,861	$ 56,075	$ (36,214)	(65)%

(1) A BOE means one barrel of oil equivalent using the ratio of six Mcf of gas to one barrel of oil.

Oil revenues

Average wellhead realized crude oil prices decreased $63.85 per Bbl, or 53%, to $55.57 per Bbl in the Current Quarter, over the Comparable Quarter. This price decrease resulted in decreased revenues by approximately

$15.8 million for the Current Quarter, as compared to the Comparable Quarter. Oil production increased by approximately 11,000 Bbls due primarily to new wells and the additional interest the Diamond M acquired in the second quarter of 2008, where volumes increased approximately 28,000 Bbls in the Current Quarter. This increase was partially offset with natural declines in the Andrews, Texas area. The increase in production partially offset the revenue decline due to sales price decreases by approximately $1.3 million in the Current Quarter over the Comparable Quarter.

Natural gas revenues

Average realized wellhead natural gas prices decreased $7.17 per Mcf, or 72%, to $2.78 per Mcf in the Current Quarter, over the Comparable Quarter. This price decrease accounted for a decrease in revenue of approximately $15.7 million. Natural gas production decreased by approximately 594,000 Mcf primarily due to declines in the Barnett Shale area caused by a production pad shut-in along with natural declines in the New Mexico Wolfcamp and south Texas areas. These production declines were partially offset by new wells added in our Barnett Shale and New Mexico Wolfcamp areas and increased sales in the Diamond M area associated with the additional interest we acquired in 2008. In addition, the overall decrease in natural gas volumes decreased revenue approximately $5.9 million for the Current Quarter as compared to the Comparable Quarter.

Cost and Expenses

	Three months ended June 30, 2009	2008	Change	Percentage Change
	($ in thousands)			
Lease operating expense	$ 5,541	$ 7,254	$ (1,713)	(24)%
Production taxes	761	2,996	(2,235)	(75)%
General and administrative	3,281	3,265	16	0%
Depreciation, depletion and amortization	5,398	10,483	(5,085)	(49)%
Total	$ 14,981	$ 23,998	$ (9,017)	(38)%

Lease operating expense

Lease operating expense decreased approximately $1.7 million, or 24%, to $5.5 million during the Current Quarter, compared to $7.2 million for the Comparable Quarter. Lease operating expense per BOE decreased to $9.03 for the Current Quarter, compared to $10.33 per BOE in the Comparable Quarter. The decrease in costs is primarily due to an overall reduction in well and lease repairs as well as lower workover expenses. This cost reduction resulted from our efforts to reduce costs across the board in response to the market downturn and a decline in vendor pricing. In addition, water disposal costs associated with our Barnett Shale and New Mexico Wolfcamp areas are down approximately $326,000 due to a reduction of new wells coming on line in the Current Quarter versus the Comparable Quarter. Additionally, we realized an approximate $100,000 cost reduction in the gathering, transportation and treating costs associated with the Hagerman Gas Gathering System.

Production taxes

Production taxes decreased $2.2 million for the Current Quarter, as compared to the Comparable Quarter. Production taxes were 3.8% of revenue for the Current Quarter compared to 5.3% of revenue for the Comparable Quarter. The decrease in production taxes is primarily due to lower tax values resulting from lower prices. Production tax rates are also lower in the Fullerton and Barnett Shale areas resulting from refunds and tax abatements granted by state regulatory agencies. Production taxes in future periods will be a function of product mix, production volumes, product prices and tax rates.

General and administrative

General and administrative expenses in the Current Quarter increased slightly by $16,000 over the Comparable Quarter. This increase was primarily caused by increases of non-cash items in stock based compensation expenses of $318,000 and a reduction in the amount of expenses we capitalized of $198,000. These increases were almost entirely offset with reductions across the board with our effort to reduce costs. On a BOE basis, general and administrative costs were $5.35 per BOE in the Current Quarter, as compared to $4.65 per BOE in the Comparable Quarter. The increase on a per BOE basis was due to the increases of non cash items as well as volumetric decreases.

Table of Contents

Depreciation, depletion and amortization

Depreciation depletion and amortization expense decreased 49%, or $5.1 million, in the Current Quarter, over the Comparable Quarter. Total depreciation, depletion and amortization per BOE was $8.79 for the Current Quarter and $14.93 for the Comparable Quarter. This decrease is primarily a result of the impairment write down which we made at the end of the year in 2008 and at the end of the quarter ended March 31, 2009. The rate at which we depreciate our oil and gas properties is dependent on our remaining oil and gas depletable cost base, anticipated future drilling and development costs and our reserve volumes.

Other income (expense)

	Three months ended June 30,			Percentage
	2009	2008	Change	Change
	($ in thousands)			
Loss on derivatives not classified as hedges	$ (13,286)	$ (71,609)	$ 58,323	81%
Interest and other income	30	32	(2)	(6)%
Interest expense, net of capitalized interest	(6,360)	(5,368)	(992)	(18)%
Other expense	(5)	(1)	(4)	(400)%
Equity in gain of pipeline venture and gathering system ventures		165	(165)	(100)%
Total	$ (19,621)	$ (76,781)	$ 57,160	(74)%

Loss on derivatives not classified as hedges

We recorded a loss of $(13.3) million in the Current Quarter for derivatives not classified as hedges, as compared to a loss of $(71.6) million for the Comparable Quarter. Of these amounts, we had a gain of $457,000 in the Current Quarter for changes in fair market value in our interest rate swaps, versus a gain of $1.4 million in the Comparable Quarter. For our natural gas derivative contracts, we had a loss of $(865,000) in the Current Quarter, versus a loss of $(9.1) million for the Comparable Quarter. For our crude oil derivative contracts we had a loss of $(12.9) million in the Current Quarter, versus a loss of $(63.9) million in the Comparable Quarter. The primary reason for the differences in the performance in our commodity derivative contracts was the due to a smaller increase in oil prices from the beginning of the Current Quarter to the end of the Current Quarter versus the same time period in the Comparable Quarter. See Note 8- Derivative Instruments .

Interest expense

Interest expense increased approximately $992,000. The Current Quarter is higher primarily due to higher average outstanding debt balances over the Comparable Quarter. Partially offsetting the increase in interest expense, our weighted average interest rate decreased to 6.96% for the Current Quarter, from 8.33% for the Comparable Quarter. Additionally, capitalized interest for the Current Quarter was approximately $519,000 and $19,000 for the Comparable Quarter.

Equity in gain of pipelines and gathering system ventures

For the Current Quarter we recorded a loss of less than $(1,000) compared to a gain of $165,000 in the Comparable Quarter for our equity investments. This change is primarily due to the acquisition in June 2008, of all the assets of the Hagerman Gas Gathering System Joint Venture. The results of operations of the Hagerman Gas Gathering System are now included in our operating income and not as an equity gain / loss item in our Statement of Operations. The current quarter activity is associated with our one remaining equity investment in West Fork Pipeline II, LP.

Table of Contents

Income taxes, deferred

Income tax benefit was approximately $5.1 million in the Current Quarter, as compared to approximately $15.5 million in the Comparable Quarter. Income tax expense for 2009 will be dependent on our earnings (loss) and is expected to be approximately 35% of income (loss) before income taxes.

Basic and diluted net loss

We had basic and diluted net loss per share of $(0.23) and $(0.70) for the Current Quarter and the Comparable Quarter, respectively. Basic and diluted weighted average common shares outstanding increased from 41.4 million shares in the Comparable Quarter to 41.6 million shares in the Current Quarter. The increase in common shares was due to the exercise in 2008 of employee stock options and publicly held warrants.

RESULTS OF OPERATIONS

For the Six Months Ended June 30, 2009 and 2008:

Our oil and natural gas revenues and production product mix are displayed in the following table for the Current and Comparable Periods.

Oil and Gas Revenues

	Revenues For the Six Months Ended June 30,		Production For the Six Months Ended June 30,	
	2009	2008	2009	2008
Oil (Bbls)	60%	51%	39%	35%
Natural gas (Mcf)	40%	49%	61%	65%
Total	100%	100%	100%	100%

The following table shows our production volumes, product sales prices and operating revenues for the indicated periods.

	Six Months Ended June 30,			Percentage
	2009	2008	Change	Change
	(in thousands except per unit data)			
Production Volumes:				
Oil (Bbls)	500	484	16	3%
Natural gas (Mcf)	4,725	5,452	(727)	(13)%
BOE [(1)]	1,288	1,393	(105)	(8)%
BOE/Day	7.1	7.7	(0.6)	(8)%
Sales Price:				
Oil (per Bbl)	$ 45.79	$ 106.32	$ (60.53)	(57)%
Natural gas (per Mcf)	$ 3.21	$ 8.90	$ (5.69)	(64)%
BOE price	$ 29.58	$ 71.80	$ (42.22)	(59)%
Operating Revenues:				
Oil	$ 22,905	$ 51,491	$ (28,586)	(56)%
Natural gas	15,185	48,525	(33,340)	(69)%
Total	$ 38,090	$ 100,016	$ (61,926)	(62)%

(1) A BOE means one barrel of oil equivalent using the ratio of six Mcf of gas to one barrel of oil.

Oil revenues

Average wellhead realized crude oil prices decreased $60.53 per Bbl, or 57%, to $45.79 per Bbl in the Current Period, over the Comparable Period. This price decrease resulted in decreased revenues by approximately $30.3 million for the Current Period, as compared to the Comparable Period. Oil production increased by approximately 16,000 Bbls due primarily to new wells and the additional interest acquired in the Diamond M area, where volumes increased approximately 57,000 Bbls in the Current Period. This increase was partially offset with natural declines in the Andrews and Fullerton areas. The increase in production partially offset the revenue decrease due to sales price decreases by approximately $1.7 million in the Current Period over the Comparable Period.

Natural gas revenues

Average realized wellhead natural gas prices decreased $5.69 per Mcf, or 64%, to $3.21 per Mcf in the Current Period, over the Comparable Period. This price decrease accounted for a decrease in revenue of approximately $26.9 million. Natural gas production decreased by approximately 727,000 Mcf primarily due to declines in the Barnett Shale area caused by a production pad shut-in partially offset by new wells added in our Barnett Shale and New Mexico Wolfcamp areas and natural declines in the south Texas area and increased sales in the Diamond M area due to our acquisition in 2008. In addition, the overall decrease in natural gas volumes decreased revenue approximately $6.4 million for the Current Period as compared to the Comparable Period.

Cost and Expenses

	Six months ended June 30,			
	2009	2008	Change	Percentage Change
	($ in thousands)			
Lease operating expense	$ 13,627	$ 14,233	$ (606)	(4)%
Production taxes	1,334	5,285	(3,951)	(75)%
General and administrative	6,714	5,833	881	15%
Depreciation, depletion and amortization	12,179	19,835	(7,656)	(39)%
Impairment of oil and natural gas properties	30,426		30,426	N/A
Total	$ 64,280	$ 45,186	$ 19,094	42%

Lease operating expense

Lease operating expense decreased approximately $606,000 or 4%, to $13.6 million during the Current Period compared to $14.2 million for the Comparable Period. Lease operating expense per BOE increased to $10.58 for the Current Period compared to $10.22 for the Comparable Period. This reduction is due primarily in reductions in well repairs and expense workovers in the Fullerton where these costs have reduced approximately $985,000. In addition we have seen an overall reduction in lease operating expenses across the board in our effort to reduce costs as well as a decline in vendor pricing. These cost reductions were partially offset with increases in lease operating costs in the Diamond M area as a result of the additional interest we acquired in late June 2008.

Production taxes

Production taxes decreased $4.0 million for the Current Period, as compared to the Comparable Period. Production taxes were 3.5% of revenue for the Current Period compared to 5.3% of revenue for the Comparable Period. The decrease in production taxes is primarily due to lower tax values resulting from lower prices. Production tax rates are also lower in the Fullerton and Barnett Shale areas resulting from tax refunds and abatements granted by state regulatory agencies. Production taxes in future periods will be a function of product mix, production volumes, product prices and tax rates.

Table of Contents

General and administrative

General and administrative expenses increased by $881,000 for the Current Period, over the Comparable Period. This increase was primarily caused by increases in non-cash items of stock based compensation expenses of $782,000 and a reduction in the amount of expenses we capitalized of $162,000. On a BOE basis, general and administrative costs were $5.21 per BOE in the Current Period, as compared to $4.19 per BOE in the Comparable Period.

Depreciation, depletion and amortization

Depreciation depletion and amortization expense decreased 39%, or $7.7 million, in the Current Period, over the Comparable Period. Total depreciation, depletion and amortization per BOE was $9.46 for the Current Period and $14.24 for the Comparable Period. This decrease is primarily a result of the impairment write down which we made at the end of the year in 2008 and at the end of the previous quarter end March 31, 2009. The rate at which we depreciate our oil and gas properties is dependent on our remaining oil and gas depletable cost base, anticipated future drilling and development costs and our reserve volumes.

Impairment of oil and natural gas properties

We recorded a $30.4 million write down in our full cost pool oil and gas property base at the end of the first quarter of the Current Period. This write down was primarily the result of declining natural gas prices during the first three months of the Current Period. The natural gas price that was used for our March 31, 2009 reserve study was $3.605/MMBtu. For our December 31, 2008 reserve study the price was $5.620/MMBtu. The crude oil price that we used for our March 31, 2009 reserve study was $49.66/Bbl, slightly above the $44.60/Bbl used for the December 31, 2008 reserve study. For our June 30, 2009 reserve study we used a price of $3.710/MMBtu for our natural gas and $69.89/Bbl for our crude oil and no impairment was necessary. We cannot make any assurances where natural gas prices and crude oil prices will be in the future, but if they decline back to or below the March 31, 2009 levels, we may experience additional impairment write downs.

Other income (expense)

	Six months ended June 30,			Percentage
	2009	2008	Change	Change
	($ in thousands)			
Loss on derivatives not classified as hedges	$ (7,521)	$ (93,495)	$ 85,974	92%
Interest and other income	99	65	34	52%
Interest expense, net of capitalized interest	(12,690)	(10,886)	(1,804)	(17)%
Other expense	(5)	(1)	(4)	(400)%
Equity in gain of pipeline venture and gathering system ventures	1	382	(381)	(100)%
Total	$ (20,116)	$ (103,935)	$ 83,819	(81)%

Loss on derivatives not classified as hedges

We recorded a loss of $(7.5) million in the Current Period for derivatives not classified as hedges as compared to a loss of $(93.5) million for the Comparable Period. Of these amounts, we had a loss of $(23,000) in the Current Period for changes in fair market value in our interest rate swaps versus a loss of $(695,000) in the Comparable Period. For our natural gas derivative contracts, we had a gain of $4.0 million in the Current Period versus a loss of $(13.7) million for the Comparable Period. For our crude oil derivative contracts we had a loss of $(11.5) million in the Current Period versus a loss of $(79.1) million in the Comparable Period. The primary reason for the differences in the performance in our commodity derivative contracts was due to a smaller increase in oil prices from the beginning of the Current Period to the end of the Current Period versus the same time period in the Comparable Period.

See Note 8- Derivative Instruments .

Interest expense

Interest expense increased approximately $1.8 million. The Current Period is higher primarily due to higher average outstanding debt balances over the Comparable Period. Partially offsetting the increase in interest expense, our weighted average interest rate decreased to 6.99% for the Current Period, from 8.78% for the Comparable Period. Also partially offsetting the increase to interest expense, capitalized interest for the Current Period was approximately $1.0 million and $44,000 for the Comparable Period.

Equity in gain of pipelines and gathering system ventures

For the Current Period we recorded a gain of $1,000 compared to a gain of $382,000 in the Comparable Period for our equity investments. This change is primarily due to the treatment of the Hagerman Gas Gathering System Joint Venture. In June 2008, we acquired all of the assets of the Hagerman Gas Gathering System Joint Venture. The results of operations of the Hagerman Gas Gathering System are now included in our operating income and not as an equity gain / loss item in our Statement of Operations. We have one remaining equity investment in West Fork Pipeline II, LP.

Income taxes, deferred

Income tax benefit was approximately $16.3 million in the Current Period, as compared to approximately $17.2 million in the Comparable Period. Income tax expense for 2009 will be dependent on our earnings (loss) and is expected to be approximately 35% of income (loss) before income taxes.

Basic and diluted net loss

We had basic and diluted net loss per share of $(0.72) and $(0.77) for the Current Period and the Comparable Period, respectively. Basic and diluted weighted average common shares outstanding increased from 41.4 million shares in the Comparable Period to 41.6 million shares in the Current Period. The increase in common shares was due to the exercise in 2008 of employee stock options and publicly held warrants.

LIQUIDITY AND CAPITAL RESOURCES

Historically, our primary cash requirements have been for exploration, development and acquisition of oil and natural gas properties, payment of derivative loss settlements and repayment of principal and interest on our debt. Our capital resources have consisted of cash flows from our oil and natural gas properties, bank borrowings supported by our oil and natural gas reserves, proceeds from derivative gain settlements, proceeds from sales of debt and equity securities and, to a lesser extent, proceeds from sales of non-core assets. Our level of earnings and cash flows depend on many factors, including the prices we receive for the oil and natural gas we produce.

Working capital decreased approximately $3.5 million as of June 30, 2009 compared with December 31, 2008. Current assets exceeded current liabilities by $25.1 million at June 30, 2009. The working capital decrease was due primarily to a decrease in asset value associated with crude oil derivatives. This reduction in value of approximately $13.8 million is as a result of higher future prices for crude oil. Cash and cash equivalents decreased by $7.5 million as of the result of paying down outstanding accounts payable. Accounts receivables associated with oil and gas sales are down $3.3 million. Of this amount, $3.5 million is associated with natural gas price declines as well as production declines associated with natural gas. The working capital declines were partially offsets with working capital increases in other areas. In particular, our accounts payable trade accounts were reduced by $11.4 million and accrued liabilities for capital activities were reduced by $7.4 million. These reductions are due to the reduction of capital spending projects through the farmout agreement with Chesapeake and the reduction in spending on capital projects in our other producing areas. Please see Note 4- Oil and Natural Gas Properties for additional information on the farmout agreement.

We maintain our cash in bank deposit and brokerage accounts which, at times, may exceed federally insured limits. As of June 30, 2009, accounts were guaranteed by the Federal Deposit Insurance Corporation (FDIC) up to $250,000 and, at that same date, we had deposits in excess of the FDIC and SIPC limits in the amount of $13.9 million. In addition we had short term investments in United States Treasury bills of $5.0 million at June 30, 2009.

Cash provided by operating activities decreased by $70.4 million in the six months ended June 30, 2009 when compared to the six months ended June 30, 2008. Operating income is different from cash provided by operating activities as operating income includes certain non-cash items such as depreciation, depletion and amortization, impairment of full cost pool and loss/gain on derivatives. These items do not impact our cash flow. The decrease between periods was primarily due to a decrease in oil and natural gas prices received in 2009 versus 2008. Our interest expense also increased due to the increased loan balance from period to period. These items were partially offset by a decrease in production taxes. This decrease was a result of the decrease in oil and natural gas sales as well as our participation in state severance tax abatement programs. In addition, our lease operating expenses decreased in 2009. This decrease was caused by a reduction in workovers and well repair partially offset by increases in our total well count from a year ago. For additional discussions regarding our change in operating results please see the Results of Operations beginning on page 28.

Cash used in investing activities decreased by approximately $138.2 million in 2009 compared to 2008. This decrease was primarily as a result of the decrease in our capital spending levels. Additions to oil and natural gas properties decreased from $123.7 million to $19.3 million or $104.4 million. This is primarily due to the farmout arrangement with Chesapeake where our capital contributions were reduced from $39.7 million to $4.1 million, a $35.6 million reduction in spending during the six months ended June 30, 2009 compared to the six months ended June 30, 2008. In addition, due to the current natural gas price environment, we have temporarily stopped drilling in our New Mexico Wolfcamp area where our capital spending has been reduced by $36.9 million. In our Permian Basin oil projects we decreased our spending by $34.7 million from a year ago. The decrease in our Permian Basin oil projects during the six months ended June 30, 2009 compared to the six months ended June 30, 2008 is primarily due to the acquisition of additional interest in the Diamond M area properties in 2008. We increased our cash flow from investing activities through our settlements on derivative instruments. In 2008, we used $22.8 million to settle derivative contracts versus receiving a net of $10.8 million in 2009 for derivatives classified as investing activities. This was primarily due to lower commodity prices as well as higher fixed prices on our derivative contracts which settled.

Cash provided by financing activities decreased by $76.4 million in 2009 compared to 2008. This is primarily as a result of our borrowing on our revolving credit facility of $77.0 million in 2008 to support our 2008 capital program. This was partially offset with the settlement of certain commodity put contracts which were classified as a financing activity due to the deferred premium aspect within these contracts.

Our 2009 capital investment budget is $29.1 million. We have incurred $19.3 million of capital expenditures through June 30, 2009. Cash flow from operating activities will be highly dependent on the success of this spending as well as on commodity pricing. Due to the farmout of our Barnett Shale interests, we are in control of most of the capital expenditures budgeted for the remainder of the year. The amount and timing of our expenditures are subject to change based upon market conditions, results of expenditures, new opportunities and other factors. See Note 4- Oil and Natural Gas Properties for further discussion of the agreement with Chesapeake Energy Corporation.

Table of Contents

We anticipate that our cash requirements for the foreseeable future, including our 2009 capital expenditures, will be supported with cash flow from operations, available cash, short term investments and proceeds from settlements of derivative contracts. Our current borrowing capacity which is supported by our oil and natural gas reserves allows for an additional $4.5 million of borrowings. We may, from time to time, seek additional financing, either in the form of increased bank borrowings, sale of debt or equity securities or other forms of financing. There can be no assurance as to the availability of any additional financing upon terms acceptable to us and conditions in the capital and debt markets may limit our ability to obtain additional capital, if necessary. Finally, current oil and natural gas prices and operating performance may be lower than we have anticipated which will adversely affect our operating cash flow. If any of the above circumstances limit our ability to fund our current activities, we may need to adjust our spending downward to levels commensurate with our capital resources. In an effort to adjust our spending levels, we have reduced overhead expenses by approximately $1.5 million, on an annualized basis, through reductions in salaries, directors fees and other general and administrative expenses.

Stockholders equity at June 30, 2009 was $78.1 million, as compared to $107.0 million at December 31, 2008. The change is primarily attributable to our net loss of approximately $(30.0) million.

Bank Borrowings Revolving Credit Facility

We maintain one bank credit facility, our Fourth Amended and Restated Credit Agreement, dated May 16, 2008, as amended on April 30, 2009.

Our Revolving Credit Agreement, with a group of bank lenders provides us with a revolving line of credit having a borrowing base limitation of $230.0 million at June 30, 2009. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of $600.0 million or the borrowing base established by the lenders. At June 30, 2009, the principal amount outstanding under our revolving credit facility was $225.0 million, excluding $445,000 reserved for our letters of credit. We have pledged substantially all of our producing oil and natural gas properties to secure the repayment of our indebtedness under the Revolving Credit Agreement.

See Note 3- Credit Arrangements for additional information concerning our bank borrowings.

Our Revolving Credit Agreement allows us to borrow, repay and reborrow amounts available under the facility. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base is redetermined by the lenders semi-annually on or about April 1 and October 1 of each year or at other times required by the lenders or at our request. The April 30, 2009 amendment reaffirmed our borrowing base of $230.0 million and changed the funded debt ratio we are required to maintain and is described below. If the outstanding principal amount of our loans ever exceeds the borrowing base, we must either provide additional collateral to the lenders or repay the outstanding principal of our loans in an amount equal to the excess. Except for principal payments that may be required because of our outstanding loans being in excess of the borrowing base, interest only is payable monthly.

As of June 30, 2009, our group of bank lenders included Citibank, N.A., BNP Paribas, Compass Bank, Bank of Scotland plc, Bank of America, N.A., Texas Capital Bank, N.A., Western National Bank and West Texas National Bank. None of the bank lenders held more than 21% of the facility at June 30, 2009.

Loans made to us under this revolving credit facility bear interest on the base rate of Citibank, N.A. or the LIBOR rate, at our election.

The interest rate we are required to pay on our borrowings, including the applicable margin, may never be less than 4.75%. At June 30, 2009, our base rate, plus the applicable margin, was 4.75% on $225.0 million, the outstanding principal amount of our revolving loan on that same date.

In the case of base rate loans, interest is payable on the last day of each month. In the case of LIBOR loans, interest is payable on the last day of each applicable interest period.

If the borrowing base is increased, we are also required to pay a fee of 0.375% on the amount of any increase.

All outstanding principal and accrued and unpaid interest under the revolving credit facility is due and payable on December 31, 2013. The maturity date of our outstanding loans may be accelerated by the lenders upon the occurrence of an event of default under the Revolving Credit Agreement.

The Revolving Credit Agreement contains various restrictive covenants, including (i) maintenance of a minimum current ratio, (ii) maintenance of a maximum ratio of funded indebtedness to earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), (iii) maintenance of a minimum net worth, (iv) prohibition of payment of dividends and (v) restrictions on incurrence of additional debt. As amended, our ratio of Consolidated Funded Debt to Consolidated EBITDA may not exceed 5.00 to 1.00 during 2009, 4.25 to 1.00 during 2010 or 4.00 to 1.00 during 2011 and thereafter. If we breach any of the provisions of the credit agreement, including the financial covenants, and are unable to obtain waivers from our lenders, they would be entitled to declare an event of default, at which point the entire unpaid principal balance of the loans, together with all accrued and unpaid interest, would become immediately due and payable. Because substantially all of our assets are pledged as collateral under the revolving facility, if our lenders declare an event of default, they would be entitled to foreclose on and take possession of our assets.

In addition to the restrictive covenants contained in the Revolving Credit Agreement, our lenders have the unilateral authority to redetermine the borrowing base at any time they desire to do so. Any such unscheduled redetermination could result in the requirement for us to provide additional collateral or repay any borrowing base deficiency as described above. Although our lenders have not, in the past, initiated an unscheduled borrowing base determination, current economic conditions and the matters described under Item 1A. Risk Factors could cause the lenders to initiate such an unscheduled redetermination. Also see Item 1A. Risk Factors in our Form 10-K for the year ended December 31, 2008 filed with the SEC on February 23, 2009.

As of June 30, 2009 we were in compliance with the covenants in our Revolving Credit Agreement.

Senior Notes

At June 30, 2009, the carrying value of our $150.0 million $10^{1}/4$% senior notes due 2014, or senior notes , was $146.2 million. The senior notes mature on August 1, 2014 and bear interest at 10.25%, per annum on the principal amount. Interest is payable semi-annually on February 1 and August 1 of each year to holders of record at the close of business on the preceding January 15 and July 15, respectively, and payment commenced on February 1, 2008. Prior to August 1, 2010, we may redeem up to 35% of the senior notes for a price equal to 110.250% of the original principal amount of the senior notes with the proceeds of certain equity offerings. On or after August 1, 2011 we may redeem all or some of the senior notes at a redemption price that will decrease from 105.125% of the principal amount of the senior notes to 100% of the principal amount on August 1, 2013. In addition, prior to August 1, 2011, we may redeem some or all of the senior notes at a redemption price equal to 100% of the principal amount of the senior notes to be redeemed, plus a make-whole premium, plus any accrued and unpaid interest. Generally, the make-whole premium is an amount equal to the greater of (a) 1% of the principal amount of the senior notes being redeemed and (b) the excess of the present value of the redemption price of such notes as of August 1, 2011 plus all required interest payments due through August 1, 2011 (computed at a discount rate equal to a specified U.S. Treasury Rate plus 50 basis points), over the principal amount of the senior notes being redeemed.

Table of Contents

The Indenture governing the senior notes restricts our ability to: (i) borrow money; (ii) issue redeemable and preferred stock; (iii) pay distributions or dividends; (iv) make investments; (v) create liens without securing the senior notes; (vi) enter into agreements that restrict dividends from subsidiaries; (vii) sell certain assets or merge with or into other companies; (viii) enter into transactions with affiliates; (ix) guarantee indebtedness; and (x) enter into new lines of business.

As of June 30, 2009 we were in compliance with the covenants in the Indenture.

Debt Ratings

We receive debt credit ratings from Standard & Poor s Ratings Group, Inc. (S&P) and Moody s Investors Service, Inc. (Moody s), which are subject to regular reviews. S&P s rating for Parallel is B with a negative outlook. Moody s Long-Term Corporate rating is B3 with a negative outlook. S&P and Moody s consider many factors in determining our ratings, including production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively impact our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Interest Incurred

For the Current Period, the aggregate interest incurred under our Revolving Credit Agreement and our senior notes was approximately $13.0 million. Bank fees and note discount amortization was approximately $588,000 for the Current Period and interest capitalized was approximately $1.0 million.

Commodity Price Risk Management Transactions and Effects of Derivative Instruments

We enter into derivative contracts to provide a measure of stability in the cash flows associated with our oil and natural gas production and interest rate payments and to manage exposure to commodity price and interest rate risk. Our objective is to lock in a range of oil and natural gas prices and to limit variability in our cash interest payments. In addition, our revolving credit facility requires us to maintain derivative financial instruments which limit our exposure to fluctuating commodity prices covering at least 50% of our estimated monthly production of oil and natural gas extending 24 months into the future. The derivative trade arrangements we have employed include collars, costless collars, floors or purchased puts, oil, and interest rate swaps.

All derivative contracts at June 30, 2009 were accounted for by mark-to-market accounting whereby changes in fair value were charged to earnings. Changes in the fair values of derivatives are recorded in our Statements of Operations as these changes occur in Other income (expense), net . To the extent commodity prices in 2009 and beyond decrease, we will report a gain, but if there are no further changes in prices, our revenue will be correspondingly lower (than if there had been no price decrease) when the production is sold.

We are exposed to credit risk in the event of nonperformance by the counterparties to our derivative trade instruments. We actively monitor our credit risks related to financial institutions and counterparties including monitoring credit agency ratings, financial position and current news to mitigate this credit risk. We minimize credit risk in derivative instruments by entering into transactions with counterparties that are parties to our credit facility.

We adopted SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS 161), effective January 1, 2009 for all financial assets and liabilities. SFAS 161 requires enhanced disclosures about an entity s derivative and hedging activities and thereby improves transparency of financial reporting. Entities are required to provide enhanced disclosure 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)

(39)

how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flow.

We adopted SFAS No. 157, *Fair Value Measurement,* (SFAS 157) effective January 1, 2008 to measure fair value of our derivatives, which had no significant effect on our financial position or operating results. As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

This statement requires fair value measurements to be classified and disclosed in categories of Level 1, Level 2, or Level 3, with Level 1 reflecting fair value measurements based on the most observable and active markets. During periods of market disruption, including periods of volatile oil and natural gas prices, rapid credit contraction or illiquidity, it may be difficult to value certain of our derivative instruments if trading becomes less frequent and/or market data becomes less observable. There may be certain asset classes that were in active markets with observable data that become illiquid due to the current financial environment. In such cases, more derivative instruments may fall to Level 3 and thus require more subjectivity and management judgment. As such, valuations may include inputs and assumptions that are less observable or require greater estimation as well as valuation methods which are more sophisticated or require greater estimation thereby resulting in valuations with less certainty. Further, rapidly changing and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our financial statements and the period-to-period changes in value could vary significantly. Increases or decreases in value may have a material effect on our results of operations or financial condition. Please read Note 8- Derivative Instruments for additional information about the different categories of our fair value measurements under SFAS 157.

Management of risk requires, among other things, policies and procedures to record properly and verify a number of transactions and events. We have devoted resources to develop our risk management policies and procedures and expect to continue to do so in the future. Nonetheless, our policies and procedures may not be comprehensive. Many of our methods for managing risk and exposures are based upon the use of observed historical market behavior or statistics based on historical models. As a result, these methods may not fully predict future exposures, which can be significantly greater than our historical measures indicate. Other risk management methods depend upon the evaluation of information regarding markets, or other matters that is publicly available or otherwise accessible to us. This information may not always be accurate, complete, up-to-date or properly evaluated and our risk management policies and procedures may leave us exposed to unidentified or unanticipated risk, which could negatively affect our business. See Quantitative and Qualitative Disclosures About Market Risk under Item 3 in this Form 10-Q and in our 2008 Form 10-K beginning on page 74.

Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

We have contractual obligations and commitments that may affect our financial position. However, based on our assessment of the provisions and circumstances of our contractual obligations and commitments in existence at June 30, 2009, we do not believe there will be an adverse effect on our results of operations, financial condition or liquidity.

Our contractual obligations include long-term debt, operating leases, drilling commitments, asset retirement obligations, earn-out obligations and derivative obligations. From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of June 30, 2009, the material off-balance sheet arrangements and transactions that we had entered into included (i) undrawn letters of credit in the aggregate face amount of $445,000, (ii) operating lease agreements and, (iii) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices. Other than the off-balance sheet arrangements described above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our requirements for capital resources.

Trends and Outlook

Our business is influenced by trends that affect the oil and natural gas industry. In particular, recent declines in oil and natural gas prices and recent economic trends could adversely affect our business, liquidity, results of operations and financial conditions.

Our business is increasingly subject to the adverse trends that have taken place in the global capital markets recently. The recent events in the credit and stock markets indicate a high likelihood of a continuation of, and probable further expansion of, the economic weakness in the U.S. economy that began over one year ago. The spillover of deepening fears about our banking system may adversely impact investor confidence in us, our banking relationships, and the liquidity and financial condition of third parties with whom we conduct operations.

We continue to face the challenges of weakness in the U.S. financial markets, investor anxiety over the U.S. economy, rating agency downgrades of various financial issuers, unresolved issues with structured investment vehicles, deleveraging of financial institutions and hedge funds and dislocation in the inter-bank market. Continued volatility, changes in interest rates, defaults, market liquidity, declines in equity prices, and the strengthening or weakening of foreign currencies against the U.S. dollar, individually or in tandem, could have a material adverse effect on our liquidity, results of operations, financial condition or cash flows through realized losses and impairments.

Due to deteriorating market conditions, we revised our 2009 capital budget to $29.1 million. Of this amount, we have spent approximately $19.3 million through June 30, 2009. We also entered into the Barnet Shale Farmout Agreement as described in Note 4 Oil and Natural Gas Properties . We have also implemented steps to reduce overhead expenses by approximately $1.5 million on an annualized basis. These reductions in cash expenditures were implemented late in the second quarter and we anticipate the full impact of the cost savings to be realized in future periods.

As of June 30, 2009, we had approximately $371.2 million of long-term indebtedness outstanding, representing 83% of our total capitalization. This indebtedness consists of approximately $225.0 million of borrowings under our senior secured revolving credit facility and $146.2 million under our Senior Notes. We may also incur additional indebtedness in the future. Our substantial leverage exposes us to significant risk during periods of decreasing commodity prices and economic downturn such as the one we currently face, since our cash flows may decrease and our interest expense obligations could increase. The risks associated with our substantial leverage could be even greater if we incur additional indebtedness. If our cash flows and capital resources are insufficient to fund our debt service obligations or our requirements under our other long-term liabilities, we could face substantial liquidity problems and may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful, and therefore we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations.

The oil and natural gas industry is capital intensive. We make, and anticipate that we will continue to make, capital expenditures in the exploration for**,** development and acquisition of oil and natural gas reserves. Historically, our capital expenditures have been financed primarily with:

- internally generated cash from operations;
- proceeds from bank borrowings;
- proceeds from sales of equity and debt securities; and

Table of Contents

- proceeds from sales of non-core assets.

The continued availability of these capital sources depends upon a number of variables, including:

- our proved reserves;
- the volumes of oil and natural gas we produce from existing wells;
- the prices at which we sell oil and natural gas;
- our ability to acquire, locate and produce new reserves;
- events occurring within the global capital markets; and
- results from re-determinations of the borrowing base.

Each of these variables materially affects our borrowing capacity. We may from time to time seek additional financing in the form of:

- increased bank borrowings;
- additional sales of our debt or equity securities;
- sales of non-core properties;
- other forms of financing; or
- a combination of the above.

Except for the existing revolving credit facility we have with our bank lenders, we do not currently have any agreements for any future financing and there can be no assurance as to the availability or terms of any such future financing.

Oil and Natural Gas Price Trends

Changes in oil and natural gas prices significantly affect our revenues, financial condition, cash flows and borrowing capacity. Markets for oil and natural gas have historically been volatile and we expect this trend to continue. Prices for oil and natural gas typically fluctuate in response to relatively minor changes in supply and demand, market uncertainty, seasonal, political and other factors beyond our control. We are unable to accurately predict the prices we receive for our oil and natural gas. Accordingly, any significant or sustained declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices also may reduce the amount of oil or natural gas that we can produce economically.

Our capital expenditure budgets are highly dependent on future oil and natural gas prices.

For the six months ended June 30, 2009 and 2008, the average realized sales price for our oil and natural gas was $29.58 and $71.80 per BOE, respectively.

Production Trends

We recognize that oil and gas production from a given well naturally decreases over time and that a downward trend in our overall production could occur unless these natural declines are offset by additional production from drilling, workover or recompletion activity, or acquisitions of producing properties. If any production declines we experience are other than a temporary trend, and if we cannot

Table of Contents

economically replace our reserves, our results of operations may be materially adversely affected and our stock price may decline. Our future growth will depend upon our ability to continue to add oil and natural gas reserves in excess of production at a reasonable cost.

Production growth in our Barnett Shale investments will be limited due to the farmout agreement with Chesapeake. Please see Note 4- Oil and Natural Gas Properties for additional information. We have also delayed future development plans in our New Mexico Wolfcamp project as we wait to see where natural gas prices and development costs are heading. This will slow down the production increases that we have seen in the past in this area. However, we anticipate that this decline in production can be quickly offset with new wells as soon as natural gas prices recover and or development costs decline based on the recent results of the wells that we completed in late 2008.

Due to limited development, our production has decreased in accordance with normal decline curves for our principal Permian Basin oil properties and south Texas gas properties. We anticipate a halt in this decline in oil production with the implementation of waterflood procedures in our Harris unit and the commencement of waterflooding on our Carm-Ann properties in the near term. However, we will continue to monitor our production levels and depending on commodity prices and development costs will act accordingly to stave off any significant production declines.

Lease Operating Expense Trends

The level of drilling, workover and maintenance activity in the primary areas in which we operate and produce has dramatically decreased. Service rates charged by oil field service companies have begun to decline during recent periods and electrical costs have also declined recently. We have also taken measures to reduce lease operating expenses through various cost control measures. Based on these factors, we anticipate to see a positive impact of declines in our per BOE lease operating expense throughout the remainder of 2009. We anticipate declines in production costs associated with reduced energy pricing, particularly in the case of our Permian Basin oil properties. Finally, with lower commodity prices, production taxes will be lower as these costs are directly related to sales values.

Interest Expense Trends

As a result of having increased our borrowings by $62.5 million at the end of the fourth quarter of 2008, we expect a corresponding increase in our annual interest expense for the remainder of 2009. An increase in interest rates would also negatively impact our interest expense.

Income Taxes

In accordance with SFAS 109, *Accounting for Income Taxes* , we continually assess our ability to use all of our federal net operating loss carryforwards and state operating loss credit carryforwards that result from substantial income tax deductions and prior year losses on a quarterly basis. We consider future federal and state taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, they will be reduced by a valuation allowance. At this time, we believe that it is more likely than not that we utilize all of our federal net operating loss carryforwards and state operating loss credit carryforwards in connection with federal and state income tax generated in the future. We based this conclusion on an evaluation of our future cash flows from our reserve report, estimates related to general and administrative costs, estimated net proceeds from derivatives and the interest expenses we anticipate to incur.

Recent Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations,* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non- controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be the Company s fiscal year 2009. The adoption of SFAS 141(R), effective January 1, 2009, has had no effect on our financial position or results of operations as we have made no acquisitions during the six months ended June 30, 2009. However, the impact, if any, will depend on the nature and size of business combinations we consummate thereafter.

In February 2008, the FASB issued Staff Position No. 157-2, *Effective Date of FASB Statement No. 157* (FSP 157-2), which granted a one-year deferral of the effective date of SFAS No. 157 as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and asset retirement obligations). Beginning January 1, 2009, we applied SFAS No. 157 to non-financial assets and liabilities. The adoption of SFAS No. 157 did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* (SFAS 161). This statement is intended to improve transparency in financial reporting by requiring enhanced disclosures of an entity s derivative instruments and hedging activities and their effects on the entity s financial position, financial performance, and cash flows. SFAS 161 applies to all derivative instruments within the scope of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities,* (SFAS 133), as well as related hedged items, bifurcated derivatives, and nonderivative instruments that are designated and qualify as hedging instruments. Entities with instruments subject to SFAS 161 must provide expanded disclosures. SFAS 161 is effective prospectively for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application permitted. We applied SFAS 161 beginning January 1, 2009. The adoption of SFAS No. 161 has not had an impact on our financial position or results of operations.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles,* (SFAS 162), which becomes effective for the Company 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With General Accepted Accounting Principles*. This standard identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements that are presented in conformity with generally accepted accounting principles. We do not anticipate that this pronouncement will have a material impact on our results of operations or financial position.

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting*. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations.

The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. The Company has not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices, on its disclosures, financial position or results of operations.

In April 2009, the FASB issued FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP 107-1). FSP 107-1 amends FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments,* to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This FSP also amends APB Opinion No. 28, *Interim Financial Reporting,* to require those disclosures in summarized financial information at interim reporting periods. This FSP shall be effective for interim reporting periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. An entity may early adopt this FSP only if it also elects to early adopt FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* and FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*. This FSP does not require disclosures for earlier periods presented for comparative purposes at initial adoption. In periods after initial adoption, this FSP requires comparative disclosures only for periods ending after initial adoption. We do not anticipate that this pronouncement will have a material impact on our results of operations or financial position.

In April 2009, the FASB issued FASB Staff Position FAS 141-(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies* (FSP 141-(R)-1). FSP 141-(R)-1 amends and clarifies FASB Statement No. 141 (revised 2007), *Business Combinations* to address application issues raised by preparers, auditors, and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP shall be effective for assets or liabilities arising from contingencies in 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. The impact, if any, will depend on the nature and terms of business combinations we consummate after the effective date.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS 165), which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In particular, this Statement sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. This Statement shall be effective for interim or annual financial periods ending after June 15, 2009, and shall be applied prospectively. We adopted SFAS 165 beginning June 30, 2009 and the adoption did not have a material impact on our financial position or results of operations. The date through which subsequent events have been evaluated is August 4, 2009, the date on which we filed our Form 10-Q with the Securities and Exchange Commission.

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification TM and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162* (SFAS 168) which establishes the *FASB Accounting Standards Codification* TM (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. This Statement shall be effective for financial statements issued for interim and annual periods ending after September 15, 2009.

Table of Contents

On the effective date of this Statement, all then-existing non-SEC accounting and reporting standards are superseded, except as noted within the SFAS 168. Concurrently, all nongrandfathered, non-SEC accounting literature not included in the Codification is deemed non-authoritative with some exceptions as noted within the literature. We do not anticipate that this pronouncement will have a material impact on our results of operations or financial position.

Critical Accounting Policies

Our critical accounting policies are included and discussed in our Annual Report on Form 10-K for the year ended December 31, 2008, as filed with the Securities and Exchange Commission on February 23, 2009. These critical accounting policies should be read in conjunction with the financial statements and the accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations included in our Annual Report on Form 10-K for the year ended December 31, 2008.

FORWARD-LOOKING STATEMENTS

Cautionary Statement Regarding Forward-Looking Statements

Some statements contained in this Quarterly Report on Form 10-Q are forward-looking statements . These forward looking statements relate to, among others, the following:

our future financial and operating performance and results;

our drilling plans and ability to secure drilling rigs to effectuate our plans;

production volumes;

our business strategy;

market prices;

sources of funds necessary to conduct operations and complete acquisitions;

development costs;

number and location of planned wells;

our future commodity price risk management activities;

our plans and forecasts; and

any other statements that are not historical facts.

We have based these forward-looking statements on our current assumptions, expectations and projections about future events.

We use the words may , will , could , expect , anticipate , estimate , believe , continue , intend , plan present value , reserves or other similar words to identify forward-looking statements. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations. We believe the assumptions and expectations reflected in these forward-looking statements are reasonable. However, we cannot give any assurance that our assumptions and expectations will prove to be correct or that we will be able to take any actions that are presently planned. All of these statements involve assumptions of future events and risks and uncertainties. Risks and uncertainties associated with forward-looking statements include, but are not limited to:

Table of Contents

- difficult and adverse conditions in the global and domestic capital and credit markets;
- continued volatility and further deterioration of the capital and credit markets;
- uncertainty about the effectiveness of the U.S. government s plan to purchase large amounts of illiquid, mortgage-backed and other securities from financial institutions;
- the impairment of financial institutions;
- exposure to financial and capital market risk;
- changes in general economic conditions, including the performance of financial markets and interest rates, which may affect our ability to raise capital and generate operating cash flow;
- unanticipated changes in industry trends;
- fluctuations in prices of oil and natural gas;
- dependent on key personnel;
- reliance on technological development and technology development programs;
- demand for oil and natural gas;
- losses due to future litigation;
- future capital requirements and availability of financing;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- competition;
- general economic conditions;
- governmental regulations and liability for environmental matters;
- receipt of amounts owed to us by purchasers of our production and counterparties to our derivative contracts;
- hedging decisions, including whether or not to hedge;
- terrorist attacks or war;
- actions of third party co-owners of interests in properties in which we also own an interest; and
- fluctuations in interest rates and availability of capital.

For these and other reasons, actual results may differ materially from those projected or implied.

We believe it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. We caution you against putting undue reliance on forward-looking statements or projecting any future results based on such statements.

Table of Contents

Before you invest in our common stock or our 10.25% senior notes, you should be aware that there are various risks associated with an investment. We have described some of these risks under Item 1A. Risk Factors on page 53 of this Quarterly Report and under Item 1A. Risk Factors beginning on page 17 of our Form 10-K for the year ended December 31, 2008.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following quantitative and qualitative information is provided about market risks and derivative instruments to which we were a party at June 30, 2009, and from which we may incur future earnings, gains or losses from changes in market interest rates and oil and natural gas prices.

Interest Rate Sensitivity as of June 30, 2009

Although we are currently protected from interest rate volatility up to $250.0 million through our senior notes and our interest rate swaps, we are exposed to interest rate volatility on lending above this level. Our only financial instruments sensitive to changes in interest rates are our bank debt and interest rate swaps. As the interest rate is variable and reflects current market conditions, the carrying value of our bank debt approximates the fair value. The table below shows principal cash flows and related interest rates by expected maturity dates. Refer to Note 3- Credit Arrangements of the Financial Statements for further discussion of our debt that is sensitive to interest rates.

	2009	2010	2011	2012	2013 and after	Total
			($ in thousands, except interest rates)			
Revolving Credit Facility (secured)	$	$	$	$	$225,000	$225,000
Interest rate	4.75%	4.75%	4.75%	4.75%	4.75%	
Senior notes	$	$	$	$	$150,000	$150,000
Interest rate	10.25%	10.25%	10.25%	10.25%	10.25%	

At June 30, 2009, we had outstanding bank loans in the aggregate principal amount of $225.0 million at a base interest rate of 4.75%, including applicable margin. Under our revolving credit facility, we may elect an interest rate based upon the agent bank s base lending rate, plus a margin ranging from 0% to 0.50%, or the LIBOR rate, plus a margin ranging from 2.75% to 3.25% per annum, depending upon the outstanding principal amount of the loans. The interest rate we are required to pay, including the applicable margin, may never be less than 4.75%. A change in the interest rate of one percent could cause an approximate $310,000 change in interest expense on a quarterly basis on the current amount of borrowings, when factoring in the interest rate protection we have with our interest rate swaps. As the interest rate is variable and reflects current market conditions, the carrying value of our bank debt approximates the fair value.

At June 30, 2009, we had outstanding senior notes in the aggregate principal amount of $150.0 million bearing interest at a rate of 10.25% per annum. The carrying value of our 10.25% senior notes at June 30, 2009 was approximately $146.2 million and their estimated fair value is approximately $104.3 million. Fair value is estimated based on market trades at or near June 30, 2009. Interest on our senior notes and their carrying value are not affected by changes in interest rates. However, the fair value of the senior notes increases as interest rates decrease and their fair value decreases as interest rates increase. Because we have no present plan or intent to redeem the senior notes, changes in their fair value are not expected to have any effect on our cash flow in the foreseeable future.

We have employed fixed interest rate swap contracts with BNP Paribas and Citibank, N.A. based on the 90-day LIBOR rates at the time of the contracts. These contracts are accounted for by mark-to-market accounting as prescribed in SFAS 133. We receive interest based on a 90-day LIBOR rate and

Table of Contents

pay the fixed rates shown below. We view these contracts as protection against future interest rate volatility. As of June 30, 2009, the fair market value of these interest rate swaps was a liability of approximately $6.6 million.

A recap for the period of time, notional amounts, fixed interest rates, and fair market value of these contracts at June 30, 2009 follows:

Period of Time	Notional Amounts *($ in millions)*	Weighted Average Fixed Interest Rates	Estimated Fair Market Value *($ in thousands)*
July 1, 2009 through December 31, 2009	$ 100	4.22%	$ (1,798)
January 1, 2010 through October 31, 2010	$ 100	4.71%	(2,777)
November 1, 2010 through December 31, 2010	$ 50	4.26%	(237)
January 1, 2011 through December 31, 2011	$ 100	4.67%	(1,804)
Total Fair Market Value			$ (6,616)

Commodity Price Sensitivity

From time to time, we execute price-risk management transactions (e.g., swaps, collars and puts) for a portion of our oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure to the instability of oil and natural gas price fluctuations. While the use of these arrangements may limit our ability to benefit from increases in the price of oil and natural gas, they also reduce our potential exposure to adverse price movements. Our price-risk management arrangements apply to only a portion of our production provides only partial price protection against declines in oil and natural gas prices and limits our potential gains from future increases in prices. None of these transactions are entered into for trading purposes. All of our derivative transactions provide for financial rather than physical settlement. Our management periodically reviews all of our price-risk management transactions, including volumes, accounting treatment, types of instruments and counterparties. These transactions are implemented by management through the execution of trades by our Chief Financial Officer after consultation with and concurrence by the Hedging and Acquisitions Committee, which includes all members of our Board of Directors.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Market risk refers to the risk of loss from adverse changes in oil and natural gas prices. Realized pricing is primarily driven by the prevailing domestic price for crude oil and spot prices applicable to the region in which we produce natural gas. Historically, prices received for oil and natural gas production have been volatile and unpredictable. We expect pricing volatility to continue. NYMEX closing oil prices ranged from a low of $86.99 per barrel to a high of $140.21 per barrel during the six months ended June 30, 2008. NYMEX closing natural gas prices during the six months ended June 30, 2008 ranged from a low of $7.62 per Mcf to a high of $13.35 per Mcf. During the six months ended June 30, 2009 NYMEX closing oil prices ranged from a low of $33.98 to a high of $72.68. NYMEX closing natural gas prices during the six months ended June 30, 2009 ranged from a low of $3.25 per Mcf to a high of $6.07 per Mcf. A significant decline in the prices of oil or natural gas could have a material adverse effect on our financial condition and results of operations.

We employ various derivative instruments in order to minimize our exposure to commodity price volatility. As of June 30, 2009, we had employed collars, puts and swaps in order to protect against this price volatility. Although all of the contracts that we have entered into are viewed as protection against price volatility, all contracts are accounted for by the mark-to-market accounting method as prescribed in SFAS 133. See Note 8- Derivative Instruments .

At June 30, 2009 we had natural gas collar and swap derivative contracts in place covering future

Table of Contents

natural gas production of approximately 7.0 Bcf. If natural gas prices stay at current levels, the settlement prices will be below the price range of the collar contracts, thus causing our counterparties to make payments to us at settlement date for these contracts. In addition, at current natural prices, the settlement prices will cause our counterparty to pay us at settlement date for our swap contracts.

Changes in commodity prices will affect the fair value of our derivative contracts as recorded on our balance sheet during future periods and, consequently, our reported net earnings. The changes in the recorded fair value of the commodity derivatives are marked to market through earnings. If commodity prices decrease, this commodity price change could have a positive impact to our earnings. Conversely, if commodity prices increase, this commodity price change will have a negative effect on earnings. Each derivative contract is evaluated separately to determine its own fair value. Due to the current volatility of both crude oil and natural gas prices, we are currently unable to estimate the effects on earnings in future periods, but based on the volume of our future oil and natural gas production covered by commodity derivative contracts, the effects may be material.

Descriptions of our active commodity derivative contracts as of June 30, 2009 are set forth below:

Put Options. Puts are options to sell an asset at a specified price. For any put transaction, the counterparty is required to make a payment to the Company if the reference floating price for any settlement period is less than the put or floor price for such contract.

In June 2008, we entered into multiple put contracts with BNP Paribas and in October 2008 we entered into a put contract with Citibank, N.A. In lieu of making premium payments for the puts at the time of entering into our put contracts, we deferred payment until the settlement dates of the contracts. Future premium payments will be netted against any payments that the counterparty may owe to us based on the floating price. Our put contracts contain a financing element, which management believes is other than insignificant, resulting in related cash settlements being classified as cash from financing activities within the Statement of Cash Flows. These settlements are disclosed as net settlements to reflect the amount of the gross settlement less the amount of the original put premium for the specific contracts being settled.

Due to the deferral of the premium payments, we will pay a total amount of premiums of $4.68 million which is $491,000 greater than if the premiums had been paid at the time of entering into the contracts. The $491,000 difference is recorded as a discount to the put premium obligations and recognized as interest expense over the terms of the contracts using the interest method. Through June 30, 2009, we had accrued approximately $183,000 to interest expense and settled premiums of approximately $320,000. Accordingly, the balance of the put premium obligations at June 30, 2009 including accrued interest is $4.1 million.

A summary of our put positions at June 30, 2009 is as follows:

Period of Time	Barrels of Oil	Floor	Estimated Fair Market Value *($ in thousands)*
July 1, 2009 through December 31, 2009	55,200	$ 100.00	$ 1,575
January 1, 2010 through December 31, 2010	280,100	$ 84.36	4,709
January 1, 2011 through December 31, 2011	146,000	$ 100.00	3,869
Total Fair Market Value			$ 10,153

Collars. Collars are contracts which combine both a put option or floor and a call option or ceiling . These contracts may or may not involve payment or receipt of cash at inception, depending on the ceiling and floor pricing.

(50)

Table of Contents

On April 8, 2009, we executed a natural gas costless collar trade for 2,000 MMBtu/day (WAHA) for calendar year 2010 with a floor of $4.70 and a ceiling of $5.65 with a total volume of 730,000 MMBtu. We also executed a second natural gas costless collar trade for 5,000 MMBtu/day (WAHA) for the months of October, November and December 2009 with a floor of $3.60 and a ceiling of $4.10 with a total volume of 460,000 MMBtu.

On June 15, 2009, we executed an oil costless collar trade for 700 Bbl/day (WTI-NYMEX) for calendar year 2011 with a floor of $70.00 and a ceiling of $94.25 with a total volume of 255,500 Bbl. We also executed a second oil costless collar trade for 1,000 Bbl/day (WTI-NYMEX) for calendar 2012 with a floor of $70.00 and a ceiling of $101.50 with a total volume of 366,000 Bbl.

A summary of our collar positions at June 30, 2009 is as follows:

Period of Time	Barrels of Oil	NYMEX Oil Prices Floor	NYMEX Oil Prices Ceiling	Estimated Fair Market Value *($ in thousands)*
July 1, 2009 through December 31, 2009	386,400	$65.71	$ 82.93	$ 417
January 1, 2010 through October 31, 2010	486,400	$63.44	$ 78.26	(1,503)
January 1, 2011 through December 31, 2011	255,500	$70.00	$ 94.50	424
January 1, 2012 through December 31, 2012	366,000	$70.00	$101.50	634
	M M Btu of Natural Gas	WAHA Gas Prices Floor	WAHA Gas Prices Ceiling	
July 1, 2009 through December 31, 2009	2,116,000	$ 6.30	$ 8.66	5,246
January 1, 2010 through December 31, 2010	4,380,000	$ 4.74	$ 5.86	(1,302)
Total Fair Market Value				$ 3,916

Commodity Swaps. Generally, swaps are an agreement to buy or sell a specified commodity for delivery in the future, at an agreed fixed price. Swap transactions convert a floating or market price into a fixed price. For any particular swap transaction, the counterparty is required to make a payment to the Company if the reference price for any settlement period is less than the swap or fixed price for such contract, and the Company is required to make a payment to the counterparty if the reference price for any settlement period is greater than the swap or fixed price for such contract. A recap for the period of time, MMBtu and swap prices are as follows:

Period of Time	M M Btu of Natural Gas	WAHA Swap Price	Estimated Fair Market Value *($ in thousands)*
July 1, 2009 through September 30, 2009	460,000	$ 3.91	$ 210

ITEM 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this Quarterly Report on Form 10-Q, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) was evaluated by our management, with the participation of our Chief Executive Officer, Larry C. Oldham (principal executive officer), and our Chief Financial Officer, Steven D. Foster (principal financial officer), in accordance with rules of the Securities Exchange Act of 1934, as amended. Based on that evaluation, Mr. Oldham and Mr. Foster have concluded that our disclosure controls and

(51)

Table of Contents

procedures were effective as of June 30, 2009 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to management and recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

There were no changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are party to ordinary routine litigation incidental to our business.

On March 24, 2008, a lawsuit was filed in the 24th District Court of Jackson County, Texas, against us and twenty-two other defendants in Cause No. 07-6-13069, styled Tony Kubenka, Carolyn Kubenka, Dennis J. Kallus, David J. Kallus, Mary L. Kallus, Patricia Kallus, Nova Deleon, Janie Figuerova, and Larkin Thedford, Plaintiffs v. Tri-C Resources, Inc., Marie S. Adian, Laura E. Adian, Glenn A. Fiew, Lynn Kramer, Debra Boysen, Carol J. Gleason, Alana Sue Curlee, Connie W. Marthiljohni, Claire E. Adian, Zachary D. Adian, Donald R. Starkweather, Inc., D.A. Webernick, Danette Bundick, Johnny A. Webernick, Donna Gail Glover, Sherry Shulze, William H. Webernick, Jr., TAC Resources, Inc., New Century Exploration, Inc., Allegro Investments, Inc., Parallel Petroleum Corporation and Welper Interests, LP . The nine plaintiffs in this lawsuit have named us and the other working interest owners, including Tri-C Resources, Inc., the operator, as defendants.

The plaintiffs in this lawsuit allege that they are royalty owners under oil and gas leases which are part of a pooled gas unit (the unit) located in Jackson County, Texas, and that the defendants, including us, are owners of the leasehold estate under the plaintiffs leases and others forming the unit. Plaintiffs also assert that one of the leases (other than plaintiffs leases) forming part of the unit has been terminated and, as a result, the defendants have not properly computed the royalties due to plaintiffs from unit production and have failed to properly pay royalties due to them. Plaintiffs have sued for an unspecified amount of damages, including exemplary damages, under theories of breach of contract (including breach of express and implied covenants of their leases) and conversion, and seek an accounting, a declaratory judgment to declare the rights of the parties under the leases, and attorneys fees, interest and court costs. If a judgment adverse to the defendants were entered, as a working interest owner in the leases comprising the unit, we believe our liability would be proportionate to the ownership of the other working interest owners in the leases. We have filed an answer denying any liability. Although an initial exchange of discovery has occurred, we cannot predict the ultimate outcome of this matter, but believe we have meritorious defenses and intend to vigorously contest this lawsuit. We have not established a reserve with respect to plaintiffs claims.

We received a Notice of Proposed Adjustment from the Internal Revenue Service, or the Service in May 2007 advising us of proposed adjustments to federal income tax of approximately $2.0 million for the years 2004 and 2005. Subsequent discussions with the Service placed the issues contested in a development status. In November 2007, the Service issued a letter on the matter giving us 30 days to agree or disagree with a final examination report. The final examination report reflected revisions of the previous proposed adjustments resulting in a reduced $1.1 million of additional income tax and interest charges. The decrease in proposed tax was the result of information supplied by us to the examiner as well as discussions of the applicable tax statutes and regulations. In December 2007, we filed a protest documenting our complete disagreement with the adjustments proposed on the final examination report and requested a conference with the appeals office of the Service. The examination office of the Service filed a response to our protest in February 2008 with the appeals office. In the response the additional tax was further reduced by the examination office to $720,000. In June and November of 2008, our representatives met with the Service s Appeals Officer to review specific issues related to the alternative minimum tax items in dispute. During these meetings we submitted supplements to our initial protest in further support of our position. On May 27, 2009 we received an offer written proposal from the Service where we would owe under which we would not owe any no additional taxes or interest for the years 2004 and 2005, but which would require us to reduce future alternative minimum tax net operating losses by approximately $18.6 million. We have accepted this offer and are awaiting final notification from the Service that this matter is closed. The result of this settlement offer is that our Alternative Minimum Tax Net Operating Loss s will be reduced by $18.6 million. This reduction has no direct impact on our earnings, but could accelerate the timing of future tax payments.

We are also presently a named defendant in one other lawsuit arising out of our operations in the normal course of business, which we believe is not material.

We are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject, nor have we been a party to any bankruptcy, receivership, reorganization, adjustment or similar proceeding.

ITEM 1A. RISK FACTORS

You should review and consider the information regarding certain factors which could materially affect our business, financial condition or future results set forth under Part I. Item 1A. Risk Factors in our Annual Report on Form 10-K for 2008. Except for the risk factor Certain federal income tax deductions currently available with respect to oil and gas drilling and development may be eliminated as a result of future legislation , there have been no material changes during the quarter ended June 30, 2009 to the Risk Factors set forth in Part I. Item 1A of our Annual Report on Form 10-K for 2008. Set forth below are some of the risk factors contained in our Annual Report on Form 10-K. However, we urge you to read all of the risk factors in our Annual Report on Form 10-K.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. The purpose of ACESA is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The Chairman of the CFTC has announced that the CFTC intends to conduct hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all OTC derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivative contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain federal income tax deductions currently available with respect to oil and gas drilling and development may be eliminated as a result of future legislation.

The White House released a preview of its budget for Fiscal Year 2010 on February 26, 2009, entitled A New Era of Responsibility: Renewing America s Promise. Among the new administration s proposed changes are the outright elimination of many of the key federal income tax benefits historically associated with oil and gas. Although presented in very summary form, among other significant energy tax items, the administration s budget appears to propose the complete elimination of (i) expensing of intangible drilling costs, and (ii) the percentage depletion method of deduction with respect to oil and gas wells.

Although no legislation has yet been formally introduced, the administration s apparent effective date would be January 1, 2011. It is unclear whether such proposal will be proposed as actual legislation and, if so, whether it will actually be enacted. In addition, there are other significant tax changes under discussion in the Congress. If this proposal (or others) is enacted into law, it could represent an extremely significant reduction in the tax benefits that have historically applied to certain investments in oil and gas.

We must replace oil and natural gas reserves that we produce. Failure to replace reserves may negatively affect our business.

Our net quantity of proved natural gas reserves increased by approximately 25% in 2008 as our drilling programs resulted in significant natural gas discoveries and extensions in our Barnett Shale resource natural gas project and in our New Mexico projects. However, the net quantity of our proved oil reserves decreased by approximately 25% in 2008 primarily due to the effects of reduced oil pricing between December 31, 2008 and 2007 and the effects such decrease has on the projected economic limits of oil properties. Overall, our oil and gas reserves have declined since December 31, 2006.

The following table shows the year-end trend in our total proved reserves since December 31, 2000:

	Reserves at Year-End		
Year	Oil (Bbls)	Gas (Mcf)	BOE
		(in thousands)	
2000	974	15,686	3,588
2001	916	13,947	3,241
2002	10,271	15,633	12,877
2003	12,084	16,271	14,796
2004	18,916	16,825	21,720
2005	21,192	25,237	25,398
2006	28,721	58,896	38,537
2007	28,434	57,234	37,973
2008	21,206	71,833	33,178

The net change in proved reserves for any period is the result of many factors, including:

- additions from exploratory drilling;
- revisions of existing reserves due to factors such as changes in commodity price, estimated future drilling costs in the case of proved undeveloped reserves, changes in estimated future production costs, and revisions based on changes in expectation of well performance;
- purchases of minerals in place; and
- sales of minerals in place.

Our future performance depends in part upon our ability to find, develop and acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves decline as they are depleted and we must locate and develop or acquire new oil and natural gas reserves to replace reserves being depleted by production. In addition, if the value our bank lenders attribute to our reserves and our production declines, then the amount we are able to borrow under our credit agreement will also decline. No assurance can be given that we will be able to find and develop or acquire additional reserves on an economic basis. If we cannot economically replace our reserves, our results of operations may be materially adversely affected.

General economic conditions could adversely impact our results of operations.

A further slowdown in the U.S. economy or other economic conditions affecting capital markets, such as declining oil and gas prices, failing or weakened financial institutions, inability to access cash in our bank accounts, inflation, deteriorating business conditions, interest rates and tax rates, may adversely affect our business and financial condition by reducing overall public confidence in our financial strength, by causing us to further reduce our capital expenditure program and curtail planned drilling activities or by causing the oil field service sector of the domestic oil and gas industry to reduce equipment, labor and services that would otherwise be available to us. Further, some of our properties are operated by third parties whom we depend upon for timely performance of drilling and other contractual obligations and, in some cases, for distribution to us of our proportionate share of revenues from sales of oil and natural gas we produce. If current economic conditions adversely impact our third party operators, we are exposed to the risk that drilling operations or revenue disbursements to us could be delayed. This trickle down effect could significantly harm our business, financial condition and results of operation.

The consequences of a recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenue, liquidity and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital. These events increase the likelihood that we could become highly vulnerable to further adverse general economic consequences and industry conditions and that our cash flows and financial condition may be materially adversely affected as a result thereof.

In addition, the instability and uncertainty in the financial markets has made it difficult for us to follow through with drilling operations and other business activities that we had planned on implementing before the current financial crisis. Lower oil and gas prices, the financial markets and U.S. economy have altered our ability and willingness to continue drilling operations at a pace consistent with 2008 levels.

The economic situation could also have an impact on our customers and suppliers, causing them to fail to meet their obligations to us, and on our operating partners, resulting in delays in operations or failure to make required payments. Additionally, the current economic situation could lead to reduced demand for oil and natural gas or further reductions in the prices of oil and natural gas, or both, which could have a negative impact on our financial position, results of operations and cash flows. While the ultimate outcome and impact of the current financial crisis cannot be predicted, it may have a material adverse effect on our future liquidity and financial condition.

Adverse capital and credit market conditions may significantly affect our ability to meet liquidity needs, access to capital and cost of capital.

The capital and credit markets have been experiencing extreme volatility and disruption for more than twelve months. This volatility and disruption has reached unprecedented levels. In some cases, the markets have exerted downward pressure on availability of liquidity and credit capacity for certain issuers. We need liquidity to pay our operating expenses and interest on our debt. Without sufficient liquidity, we could be forced to curtail our operations, and our business will suffer. The principal sources of our liquidity have been cash flow from our operations, bank borrowings and proceeds from the sale of our debt and equity securities.

If cash flow from operations and bank borrowings do not satisfy our needs, we may have to seek additional financing. The availability of additional financing will depend on a variety of factors such as market conditions, the general availability of credit, the volume of trading activities, the overall availability of credit to the exploration and production segment of the oil and gas industry, our credit ratings and credit capacity, and the possibility that our lenders could develop a negative perception of our long or short-term financial prospects if the level of our business activity decreases due to a market downturn. Similarly, our access to funds may be impaired if rating agencies take negative actions against us. Our internal sources of liquidity may prove to be insufficient, and in such case, we may not be able to successfully obtain additional financing on favorable terms, or at all.

Disruptions, uncertainty or volatility in the capital and credit markets may also limit our access to capital required to operate our business, most significantly our drilling operations. Such market conditions may limit our ability to: replace, in a timely manner, oil and gas reserves that we produce; meet maturing liabilities; generate revenue to meet liquidity needs; and access the capital necessary to grow our business. As such, we may be forced to delay raising capital, issue more debt or equity securities than we prefer, or bear an unattractive cost of capital which could decrease our profitability and significantly impair financing alternatives available to us. Our results of operations, financial condition, cash flows and capital position could be materially adversely affected by disruptions in the financial markets.

Difficult conditions in the global capital markets and the economy generally may materially adversely affect our business and results of operations and we do not expect these conditions to improve in the near future.

Our results of operations are materially affected by conditions in the domestic capital markets and the economy generally. The stress experienced by domestic capital markets that began in the second half of 2008 has continued and substantially increased during the first quarter of 2009. Recently, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market and a declining real estate market in the U.S. have contributed to increased volatility and diminished expectations for the economy and the markets going forward. These factors, combined with volatile oil and gas prices, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and recession. In addition, the fixed-income markets are experiencing a period of extreme volatility which has negatively impacted market liquidity conditions.

Initially, the concerns on the part of market participants were focused on the subprime segment of the mortgage-backed securities market. However, these concerns have since expanded to include a broad range of mortgage-and asset-backed and other fixed income securities, including those rated investment grade, the U.S. and international credit and interbank money markets generally, and a wide range of financial institutions and markets, asset classes and sectors. As a result, capital markets have experienced decreased liquidity, increased price volatility, credit downgrade events, and increased probabilities of default. These events and the continuing market upheavals may have an adverse effect on us because our liquidity and ability to fund our capital expenditures may be dependent in part upon our bank borrowings and access to the public capital markets. Our revenues are likely to decline in such circumstances and our profit margins could erode. In addition, in the event of extreme prolonged market events, such as the global credit crisis, we could incur significant losses. Even in the absence of a market downturn, we are exposed to substantial risk of loss due to market volatility.

Factors such as business investment, government spending, the volatility and strength of the capital markets, and inflation all affect the business and economic environment and, ultimately, the amount and profitability of our business. In an economic downturn characterized by higher unemployment, lower corporate earnings and lower business investment, our operations could be negatively impacted. Purchasers of our oil and gas production may delay or be unable to make timely payments to us. Adverse changes in the economy could affect earnings negatively and could have a material adverse effect on our business, results of operations and financial condition. The current mortgage crisis has also raised the possibility of future legislative and regulatory actions in addition to the recent enactment of the Emergency Economic Stabilization Act of 2008 (the EESA) that could further impact our business. We cannot predict whether or when such actions may occur, or what impact, if any, such actions could have on our business, results of operations and financial condition.

There can be no assurance that actions of the U.S. Government, Federal Reserve and other governmental and regulatory bodies for the purpose of stabilizing the financial markets will achieve the intended effect.

In response to the financial crises affecting the banking system and financial markets and going concern threats to investment banks and other financial institutions, on October 3, 2008, President Bush signed the EESA into law. Pursuant to the EESA, the U.S. Treasury has the authority to, among other things, purchase up to $700 billion of mortgage-backed and other securities from financial institutions for the purpose of stabilizing the financial markets. The Federal Government, Federal Reserve and other governmental and regulatory bodies have taken or are considering taking other actions to address the financial crisis. There can be no assurance as to what impact such actions will have on the financial markets, including the extreme levels of volatility currently being experienced. Such continued volatility could materially and adversely affect our business, financial condition and results of operations, or the trading price of our common stock.

The impairment of financial institutions could adversely affect us.

We have exposure to counterparties in the financial services industry, including commercial banks that we rely upon for our credit facilities. In the event of default of one or more of these counterparties, we may have exposure in the form of our ability to withdraw funds on short notice to meet our obligations and short-term investments. We also have exposure to these financial institutions in the form of derivative transactions in that the collectibility of amounts owed to us by a defaulting counterparty may be delayed or impaired. However, our derivative instruments provide rights of setoff of amounts we owe under our credit facilities against amounts owed to us by a counterparty under our derivative transactions.

If the counterparties to the derivative instruments we use to hedge our business risks default or fail to perform, we may be exposed to risks we had sought to mitigate, which could materially adversely affect our financial condition and results of operations.

We use derivative instruments to mitigate our risks in various circumstances. We enter into a variety of derivative instruments, including swaps, puts and collars with a number of counterparties who are also bank lenders under our credit facility. See Item 7A, Quantitative and Qualitative Disclosures About Market Risk in our 2008 Form 10-K. If our counterparties fail or refuse to honor their obligations under these derivative instruments, our hedges of the related risk will be ineffective. This is a more pronounced risk to us in view of the recent stresses suffered by financial institutions. Such failure could have a material adverse effect on our financial condition and results of operations. We cannot provide assurance that our counterparties will honor their obligations now or in the future. A counterparty s insolvency, inability or unwillingness to make payments required under terms of derivative instruments with us could have a material adverse effect on our financial condition and results of operations. However, our derivative instruments allow us to setoff amounts owed to us by a counterparty against amounts that are owed by us to a counterparty under our loan facility. At the date of filing this Form 10-Q Report with the Securities and Exchange Commission, our counterparties included Citibank, N.A. and BNP Paribas.

The fluctuation and volatility of oil and natural gas prices may adversely affect our business, the value of our mineral properties, our revenues and profitability.

Our business, the value of our oil and natural gas properties and our revenues and profitability are substantially dependent on prevailing prices of oil and natural gas. Our ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and natural gas prices. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often causes disruption in the market for acquiring oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for acquisitions, development and exploitation projects. From June 30, 2008 thru June 30, 2009, oil prices have fluctuated from a low of approximately $33.87 to a high of approximately $145.29 per barrel for oil traded on the New York Mercantile Exchange (NYMEX). During the same periods, natural gas prices have fluctuated from a low of $3.25 per MMBtu to a high of $13.58 per MMBtu on NYMEX. Subsequent to June 30, 2008, the prices of oil and natural gas traded on NYMEX have declined significantly. If commodity prices decline our financial condition and results of operation would be materially and adversely affected. In addition, any further and extended decline in the price of oil and natural gas could have an adverse effect on our business, the value of our properties, our borrowing capacity, revenues, profitability and cash flows from operations.

Our oil and gas operations are subject to various Federal, state and local regulations that materially affect our operations.

Matters regulated include permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances and materials produced or used in connection with oil and gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

ITEM 2. UNREGISTERED SALES OR EQUITY SECURITIES AND USE OF PROCEEDS

Under our 2004 Non-Employee Director Stock Grant Plan, each non-employee Director is entitled to receive an annual fee consisting of shares of common stock that are automatically granted on the first day of July in each year. The actual number of shares received is determined by dividing $25,000 by the average daily closing price of the common stock on the Nasdaq Global Select Market for the ten consecutive trading days commencing fifteen trading days before the first day of July of each year ($2.029). Effective July 1, 2009, in accordance with the terms of the plan, a total of 49,284 shares of common stock were granted to four non-employee Directors as follows: Jeffrey G. Shrader 12,321 shares; Edward A. Nash 12,321 shares; Martin B. Oring 12,321 shares; and Ray M. Poage 12,321 shares. The shares of common stock were issued without registration under the Securities Act of 1933, as amended, in reliance on the exemption provided by Section 4(2) of the Securities Act. Generally, shares issued under this plan are not transferable as long as the non-employee Director holding the shares remains a Director of the Company.

On May 20, 2009, the Compensation Committee granted to officers and employees of the Company stock options to purchase a total of 464,200 shares. The exercise price of the options is $2.00 per share, the grant date closing sales price of our common stock on the Nasdaq Global Select Market. All of the options are for a term of ten years and vest in four equal annual installments beginning on May 20, 2010. The options were issued without registration under the Securities Act of 1933, as amended, in reliance on Section 4(2) of the Securities Act.

Table of Contents

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Our annual meeting of stockholders was held on May 20, 2009. At the meeting, the following five persons were elected to serve as directors of Parallel for a term expiring at the 2010 annual meeting and until their respective successors are duly qualified and elected: Edward A. Nash, Larry C. Oldham, Martin B. Oring, Ray M. Poage, and Jeffrey G. Shrader. Set forth below is a tabulation of votes with respect to each nominee for director.

NAME	VOTES CAST FOR	VOTES WITHHELD
Edward A. Nash	36,991,404	1,475,821
Larry C. Oldham	37,105,343	1,361,882
Martin B. Oring	36,962,631	1,504,594
Ray M. Poage	36,991,872	1,475,353
Jeffrey G. Shrader	37,040,465	1,426,760

Also, the stockholders voted upon and ratified the appointment of BDO Seidman, LLP to serve as our independent public accountants for 2009. Set forth below is a tabulation of votes with respect to the proposal to ratify the appointment of our independent public accountants:

VOTES FOR	VOTES AGAINST	ABSTENTIONS
37,341,220	963,292	162,713

ITEM 5. OTHER INFORMATION.

As part of a review by the staff of the Securities and Exchange Commission (the Staff) of our Annual Report on Form 10-K for the year ended December 31, 2008, we received written comments from the Staff on March 31, 2009, April 28, 2009 and May 28, 2009. We have responded to all of the comments in the Staff s comment letters. The Staff s comments pertained primarily to (1) a request for us to disclose what our measures of reserve replacement and replacement percentages represent, and how these measures are calculated, (2) expanding our disclosure to provide an explanation of and the extent to which factors other than extensions and discoveries contribute materially to our replacement percentages, (3) expanding our disclosures to indicate our yearly reserve replacement ratios for 2001 through 2008, and (4) the status of a waterflood project. On June 24, 2009 we received a final notice from the Staff stating they had completed their review and had no further comments.

ITEM 6. EXHIBITS

(a) Exhibits

The following exhibits are filed herewith or incorporated by reference, as indicated:

No.	Description of Exhibit
3.1	Certificate of Incorporation of Registrant (Incorporated by reference to Exhibit 3.1 to Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
3.2	Bylaws of Registrant (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on November 30, 2007)
3.3	Certificate of Formation of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.3 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)

(60)

Table of Contents

No.	Description of Exhibit
3.4	Limited Liability Company Agreement of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.4 of the Registrant s Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.5	Certificate of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.5 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.6	Agreement of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.6 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.1	Certificate of Designations, Preferences and Rights of Serial Preferred Stock 6% Convertible Preferred Stock (Incorporated by reference to Exhibit 4.1 of Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
4.2	Certificate of Designations, Preferences and Rights of Series A Preferred Stock (Incorporated by reference to Exhibit 4.2 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)
4.3	Rights Agreement, dated as of October 5, 2000, between the Registrant and Computershare Trust Company, Inc., as Rights Agent (Incorporated by reference to Exhibit 1 of Form 8-A of the Registrant filed with the Securities and Exchange Commission on October 10, 2000)
4.4	Form of common stock certificate of the Registrant (Incorporated by reference to Exhibit No. 4.6 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.5	Warrant Purchase Agreement, dated November 20, 2001, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
4.6	Warrant Purchase Agreement, dated December 23, 2003, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
4.7	Purchase Warrant Agreement, dated as of October 1, 1980, between the Registrant and American Stock Transfer, Inc. (Incorporated by reference to Exhibit 4.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
4.8	First Amendment to Warrant Agreement, dated as of February 22, 2007, among the Registrant, Computershare Shareholder Services, Inc. and Computershare Trust Company, N.A. (Incorporated by reference to Exhibit 4.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
4.9	Form of Rule 144A $10^{1}/4$% Senior Note due 2014 (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.10	Form of IAI $10^{1}/4$% Senior Note due 2014 (Incorporated by reference to Exhibit 4.3 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.11	Form of Regulation S $10^{1}/4$% Senior Note due 2014 (Incorporated by reference to Exhibit 4.4 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)

(61)

No.	Description of Exhibit
4.12	Indenture, dated as of July 31, 2007, among the Registrant as Issuer and Wells Fargo Bank, National Association as Trustee (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.13	Registration Rights Agreement, dated as of July 31, 2007, by and among the Registrant, Jefferies & Company, Inc., Merrill Lynch, Pierce, Fenner and Smith Incorporated and BNP Paribas Securities Corp. (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.14	Purchase Agreement, dated as of July 26, 2007, by and among the Registrant, Jefferies & Company, Inc., Merrill Lynch, Pierce, Fenner and Smith Incorporated and BNP Paribas Securities Corp. (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.15	Form of $10^{1}/4$% Unrestricted Senior Note due 2014 (Incorporated by reference to Exhibit 4.13 of Form S-4 of the Registrant, Registration No. 333-148465)
	Executive Compensation Plans and Arrangements (Exhibit No. s 10.1 through 10.11):
10.1	1992 Stock Option Plan (Incorporated by reference to Exhibit 10.1 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
10.2	Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.3 of the Registrant s Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2005)
10.3	1998 Stock Option Plan (Incorporated by reference to Exhibit 10.4 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.4	2001 Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.7 of the Registrant s Form 10-Q Report for the fiscal quarter ended March 31, 2004)
10.5	2004 Non-Employee Director Stock Grant Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Form 8-K Report dated September 22, 2004)
10.6	Incentive and Retention Plan (Incorporated by reference to Exhibit 10.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.7	2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Form 8-K Report dated March 27, 2008)
10.8	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted under the Registrant s 2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K filed on June 18, 2008)
10.9	Form of Outside Director Stock Award Agreement for stock awards granted under the Registrant s 2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K filed on June 18, 2008)

10.10	Form of Outside Director Restricted Stock Agreement for restricted stock grants under the Registrant s 2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K filed on June 18, 2008)
10.11	Agreement of Limited Partnership of West Fork Pipeline Company LP (Incorporated by reference to Exhibit 10.21 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)

(62)

No.	Description of Exhibit
10.12	ISDA Master Agreement, dated as of October 13, 2005, between Parallel, L.P. and Citibank, N.A. (Incorporated by reference to Exhibit 10.5 of the Registrant s Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)
10.13	Third Amended and Restated Credit Agreement, dated as of December 23, 2005, among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C. and Citibank Texas, N.A., BNP Paribas, CitiBank F.S.B., Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland and Fortis Capital Corp. (Incorporated by reference to Exhibit No. 10.1 of the Registrant s Form 8-K Report, dated December 23, 2005, as filed with the Securities and Exchange Commission on December 30, 2005)
10.14	Second Lien Term Loan Agreement, dated November 15, 2005, among Parallel Petroleum Corporation, Parallel, L.P., BNP Paribas and Citibank Texas, N.A. (Incorporated by reference to Exhibit No. 10.4 of the Registrant s Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)
10.15	Intercreditor and Subordination Agreement, dated November 15, 2005, among Citibank Texas, N.A., BNP Paribas, Parallel Petroleum Corporation, Parallel, L.P. and Parallel, L.L.C. (Incorporated by reference to Exhibit No. 10.5 of the Registrant s Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)
10.16	Guaranty, dated as of December 23, 2005, made by Parallel, L.L.C. to and in favor of Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.23 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.17	Third Amended and Restated Pledge Agreement, dated as of December 23, 2005, between Parallel, L.L.C. and Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.24 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.18	Second Lien Guarantee and Collateral Agreement, dated as of November 15, 2005, made by Parallel Petroleum Corporation and Parallel, L.P. to and in favor of BNP Paribas (Incorporated by reference to Exhibit 10.25 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.19	Third Amendment to Third Amended and Restated Credit Agreement, dated as of July 31, 2007, among the Registrant, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland, and Fortis Capital Corp. (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K filed on August 1, 2007)
10.20	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of November 30, 2007, among the Registrant, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland, and Fortis Capital Corp. (Incorporated by reference to Exhibit 10.27 of Form S-4 of the Registrant, Registration No. 333-148465)
10.21	Hagerman Gas Gathering System Joint Venture Agreement, dated as of January 16, 2007, among the Registrant, Feagan Gathering Company and Capstone Oil and Gas Company, L.P. (Incorporated by reference to Exhibit 10.28 of Form 10-K of the Registrant for the fiscal year ended December 31, 2007)

10.22	Fourth Amended and Restated Credit Agreement, dated as of May 16, 2008, among the Registrant, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland plc, and Texas Capital Bank, N.A. (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on May 22, 2008)

(63)

Table of Contents

No.	Description of Exhibit
10.23	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 31, 2008, by and among Parallel Petroleum Corporation, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Bank of Scotland plc, Texas Capital Bank, N.A., Bank of America, N.A. and West Texas National Bank (Incorporated by reference to Exhibit 10.34 of the Registrant s Form 10-Q Report for the third fiscal quarter ended September 30, 2008)
10.24	Second Amendment to Fourth Amended and Restated Credit Agreement, executed as of February 19, 2009, by and among Parallel Petroleum Corporation, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Bank of Scotland plc, Texas Capital Bank, N.A., Bank of America, N.A. and West Texas National Bank (Incorporated by reference to Exhibit 10.24 of Form 10-K of the Registrant for the fiscal year ended December 31, 2008)
10.25	Third Amendment to Fourth Amended and Restated Credit Agreement, executed as of April 30, 2009, by and among Parallel Petroleum Corporation, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Bank of Scotland plc, Texas Capital Bank, N.A., Bank of America, N.A. and West Texas National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on May 4, 2009)
14	Code of Ethics (Incorporated by reference to Exhibit No. 14 of the Registrant s Form 10-K Report for the fiscal year ended December 31, 2003 and filed with the Securities and Exchange Commission on March 22, 2004)
*31.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
*31.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted 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.

* Filed herewith.

** Furnished herewith.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	PARALLEL PETROLEUM CORPORATION
Date: August 4, 2009	By: /s/ Larry C. Oldham Larry C. Oldham President and Chief Executive Officer
Date: August 4, 2009	By: /s/ Steven D. Foster Steven D. Foster, Chief Financial Officer

Table of Contents

INDEX TO EXHIBITS

No.	Description of Exhibit
3.1	Certificate of Incorporation of Registrant (Incorporated by reference to Exhibit 3.1 to Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
3.2	Bylaws of Registrant (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on November 30, 2007)
3.3	Certificate of Formation of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.3 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.4	Limited Liability Company Agreement of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.4 of the Registrant s Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.5	Certificate of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.5 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.6	Agreement of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.6 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.1	Certificate of Designations, Preferences and Rights of Serial Preferred Stock 6% Convertible Preferred Stock (Incorporated by reference to Exhibit 4.1 of Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
4.2	Certificate of Designations, Preferences and Rights of Series A Preferred Stock (Incorporated by reference to Exhibit 4.2 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)
4.3	Rights Agreement, dated as of October 5, 2000, between the Registrant and Computershare Trust Company, Inc., as Rights Agent (Incorporated by reference to Exhibit 1 of Form 8-A of the Registrant filed with the Securities and Exchange Commission on October 10, 2000)
4.4	Form of common stock certificate of the Registrant (Incorporated by reference to Exhibit No. 4.6 of the Registrant s Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.5	Warrant Purchase Agreement, dated November 20, 2001, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
4.6	Warrant Purchase Agreement, dated December 23, 2003, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
4.7	Purchase Warrant Agreement, dated as of October 1, 1980, between the Registrant and American Stock Transfer, Inc. (Incorporated by reference to Exhibit 4.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)

4.8	First Amendment to Warrant Agreement, dated as of February 22, 2007, among the Registrant, Computershare Shareholder Services, Inc. and Computershare Trust Company, N.A. (Incorporated by reference to Exhibit 4.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)

No.	Description of Exhibit
4.9	Form of Rule 144A 10$^{1}/4$% Senior Note due 2014 (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.10	Form of IAI 10$^{1}/4$% Senior Note due 2014 (Incorporated by reference to Exhibit 4.3 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.11	Form of Regulation S 10$^{1}/4$% Senior Note due 2014 (Incorporated by reference to Exhibit 4.4 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.12	Indenture, dated as of July 31, 2007, among the Registrant as Issuer and Wells Fargo Bank, National Association as Trustee (Incorporated by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.13	Registration Rights Agreement, dated as of July 31, 2007, by and among the Registrant, Jefferies & Company, Inc., Merrill Lynch, Pierce, Fenner and Smith Incorporated and BNP Paribas Securities Corp. (Incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.14	Purchase Agreement, dated as of July 26, 2007, by and among the Registrant, Jefferies & Company, Inc., Merrill Lynch, Pierce, Fenner and Smith Incorporated and BNP Paribas Securities Corp. (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed on August 1, 2007)
4.15	Form of 10$^{1}/4$% Unrestricted Senior Note due 2014 (Incorporated by reference to Exhibit 4.13 of Form S-4 of the Registrant, Registration No. 333-148465)
	Executive Compensation Plans and Arrangements (Exhibit No. s 10.1 through 10.11):
10.1	1992 Stock Option Plan (Incorporated by reference to Exhibit 10.1 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
10.2	Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.3 of the Registrant s Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2005)
10.3	1998 Stock Option Plan (Incorporated by reference to Exhibit 10.4 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.4	2001 Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.7 of the Registrant s Form 10-Q Report for the fiscal quarter ended March 31, 2004)
10.5	2004 Non-Employee Director Stock Grant Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Form 8-K Report dated September 22, 2004)
10.6	Incentive and Retention Plan (Incorporated by reference to Exhibit 10.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.7	

	2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.1 of the Registrant s Form 8-K Report dated March 27, 2008)
10.8	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted under the Registrant s 2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.2 of the Registrant s Current Report on Form 8-K filed on June 18, 2008)
10.9	Form of Outside Director Stock Award Agreement for stock awards granted under the Registrant s 2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K filed on June 18, 2008)

No.	Description of Exhibit
10.10	Form of Outside Director Restricted Stock Agreement for restricted stock grants under the Registrant s 2008 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.4 of the Registrant s Current Report on Form 8-K filed on June 18, 2008)
10.11	Agreement of Limited Partnership of West Fork Pipeline Company LP (Incorporated by reference to Exhibit 10.21 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
10.12	ISDA Master Agreement, dated as of October 13, 2005, between Parallel, L.P. and Citibank, N.A. (Incorporated by reference to Exhibit 10.5 of the Registrant s Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)
10.13	Third Amended and Restated Credit Agreement, dated as of December 23, 2005, among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C. and Citibank Texas, N.A., BNP Paribas, CitiBank F.S.B., Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland and Fortis Capital Corp. (Incorporated by reference to Exhibit No. 10.1 of the Registrant s Form 8-K Report, dated December 23, 2005, as filed with the Securities and Exchange Commission on December 30, 2005)
10.14	Second Lien Term Loan Agreement, dated November 15, 2005, among Parallel Petroleum Corporation, Parallel, L.P., BNP Paribas and Citibank Texas, N.A. (Incorporated by reference to Exhibit No. 10.4 of the Registrant s Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)
10.15	Intercreditor and Subordination Agreement, dated November 15, 2005, among Citibank Texas, N.A., BNP Paribas, Parallel Petroleum Corporation, Parallel, L.P. and Parallel, L.L.C. (Incorporated by reference to Exhibit No. 10.5 of the Registrant s Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)
10.16	Guaranty, dated as of December 23, 2005, made by Parallel, L.L.C. to and in favor of Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.23 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.17	Third Amended and Restated Pledge Agreement, dated as of December 23, 2005, between Parallel, L.L.C. and Citibank Texas, N.A. (Incorporated by reference to Exhibit 10.24 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.18	Second Lien Guarantee and Collateral Agreement, dated as of November 15, 2005, made by Parallel Petroleum Corporation and Parallel, L.P. to and in favor of BNP Paribas (Incorporated by reference to Exhibit 10.25 of Form 10-K of the Registrant for the fiscal year ended December 31, 2006)
10.19	Third Amendment to Third Amended and Restated Credit Agreement, dated as of July 31, 2007, among the Registrant, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland, and Fortis Capital Corp. (Incorporated by reference to Exhibit 10.3 of the Registrant s Current Report on Form 8-K filed on August 1, 2007)
10.20	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of November 30, 2007, among the Registrant, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank,

	Comerica Bank, Bank of Scotland, and Fortis Capital Corp. (Incorporated by reference to Exhibit 10.27 of Form S-4 of the Registrant, Registration No. 333-148465)
10.21	Hagerman Gas Gathering System Joint Venture Agreement, dated as of January 16, 2007, among the Registrant, Feagan Gathering Company and Capstone Oil and Gas Company, L.P. (Incorporated by reference to Exhibit 10.28 of Form 10-K of the Registrant for the fiscal year ended December 31, 2007)

No.	Description of Exhibit
10.22	Fourth Amended and Restated Credit Agreement, dated as of May 16, 2008, among the Registrant, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland plc, and Texas Capital Bank, N.A. (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on May 22, 2008)
10.23	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 31, 2008, by and among Parallel Petroleum Corporation, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Bank of Scotland plc, Texas Capital Bank, N.A., Bank of America, N.A. and West Texas National Bank (Incorporated by reference to Exhibit 10.34 of the Registrant s Form 10-Q Report for the third fiscal quarter ended September 30, 2008)
10.24	Second Amendment to Fourth Amended and Restated Credit Agreement, executed as of February 19, 2009, by and among Parallel Petroleum Corporation, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Bank of Scotland plc, Texas Capital Bank, N.A., Bank of America, N.A. and West Texas National Bank (Incorporated by reference to Exhibit 10.24 of Form 10-K of the Registrant for the fiscal year ended December 31, 2008)
10.25	Third Amendment to Fourth Amended and Restated Credit Agreement, executed as of April 30, 2009, by and among Parallel Petroleum Corporation, Citibank, N.A., BNP Paribas, Western National Bank, Compass Bank, Bank of Scotland plc, Texas Capital Bank, N.A., Bank of America, N.A. and West Texas National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant s Current Report on Form 8-K filed on May 4, 2009)
14	Code of Ethics (Incorporated by reference to Exhibit No. 14 of the Registrant s Form 10-K Report for the fiscal year ended December 31, 2003 and filed with the Securities and Exchange Commission on March 22, 2004)
*31.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
*31.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted 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.

* Filed herewith.

** Furnished herewith.