DENBURY RESOURCES INC
Form 10-Q
August 10, 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

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
Commission file number 1-12935
DENBURY RESOURCES INC.
(Exact name of Registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdictions of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5100 Tennyson Parkway Suite 1200 Plano, TX	**75024**
(Address of principal executive offices)	*(Zip code)*

Registrant s telephone number, including area code: **(972) 673-2000**

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 þ No o

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

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

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

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

Class	**Outstanding at July 31, 2009**
Common Stock, $.001 par value	249,438,000

INDEX

Table of Contents

DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except shares)

	June 30, 2009	December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 59,959	$ 17,069
Accrued production receivable	101,325	67,805
Trade and other receivables, net of allowance of $407 and $377	60,798	80,579
Derivative assets	39,279	249,746
Total current assets	261,361	415,199
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	3,484,536	3,386,606
Unevaluated	192,727	235,403
CO_2 properties, equipment and pipelines	1,283,135	899,542
Other	77,760	70,328
Less accumulated depletion, depreciation and impairment	(1,711,412)	(1,589,682)
Net property and equipment	3,326,746	3,002,197
Deposits on property under option or contract		48,917
Other assets	131,751	123,361
Goodwill	138,740	
Total assets	$ 3,858,598	$ 3,589,674
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 195,904	$ 202,633
Oil and gas production payable	76,259	85,833
Derivative liabilities	64,955	
Deferred revenue Genesis	4,070	4,070
Deferred tax liability	24,825	89,024
Current maturities of long-term debt	4,586	4,507
Total current liabilities	370,599	386,067
Long-term liabilities		
Long-term debt Genesis	250,653	251,047
Long-term debt	969,451	601,720

Asset retirement obligations	46,289	43,352
Deferred revenue Genesis	17,959	19,957
Deferred tax liability	408,641	433,210
Derivative liabilities	21,372	
Other	18,699	14,253
Total long-term liabilities	1,733,064	1,363,539
Stockholders equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding		
Common stock, $.001 par value, 600,000,000 shares authorized; 249,597,135 and 248,005,874 shares issued at June 30, 2009 and December 31, 2008, respectively	249	248
Paid-in capital in excess of par	724,968	707,702
Retained earnings	1,034,038	1,139,575
Accumulated other comprehensive loss	(592)	(627)
Treasury stock, at cost, 247,680 and 446,287 shares at June 30, 2009 and December 31, 2008, respectively	(3,728)	(6,830)
Total stockholders equity	1,754,935	1,840,068
Total liabilities and stockholders equity	$ 3,858,598	$ 3,589,674

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenues and other income				
Oil, natural gas and related product sales	$ 211,552	$ 413,243	$ 379,621	$ 726,440
CO_2 sales and transportation fees	2,884	3,383	6,049	6,234
Interest income and other	2,956	1,359	5,481	2,646
Total revenues	217,392	417,985	391,151	735,320
Expenses				
Lease operating expenses	83,658	76,825	158,608	142,826
Production taxes and marketing expenses	8,739	18,688	15,739	33,874
Transportation expense Genesis	2,045	1,842	4,237	3,392
CO_2 operating expenses	1,095	453	2,395	1,596
General and administrative	33,135	14,811	55,790	30,816
Interest, net of amounts capitalized of $15,454, $5,545, $27,827, and $12,811, respectively	14,904	8,141	27,101	13,082
Depletion, depreciation and amortization	61,695	54,733	123,620	104,572
Commodity derivative expense	152,789	58,817	173,304	105,598
Total expenses	358,060	234,310	560,794	435,756
Income (loss) before income taxes	(140,668)	183,675	(169,643)	299,564
Income tax provision (benefit)				
Current income taxes	24,127	10,844	24,300	32,080
Deferred income taxes	(77,555)	58,778	(88,406)	80,429
Net income (loss)	$ (87,240)	$ 114,053	$ (105,537)	$ 187,055
Net income (loss) per common share basic	$ (0.35)	$ 0.47	$ (0.43)	$ 0.77
Net income (loss) per common share diluted	$ (0.35)	$ 0.45	$ (0.43)	$ 0.74
Weighted average common shares outstanding				
Basic	246,084	243,623	245,830	243,189
Diluted	246,084	252,401	245,830	252,603

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Six Months Ended June 30,	
	2009	2008
Cash flow from operating activities:		
Net income (loss)	$ (105,537)	$ 187,055
Adjustments needed to reconcile to net cash flow provided by operations:		
Depletion, depreciation and amortization	123,620	104,572
Deferred income taxes	(88,406)	80,429
Deferred revenue Genesis	(1,998)	(2,182)
Stock-based compensation	16,566	7,385
Non-cash fair value derivative adjustments	301,197	69,003
Founder s retirement compensation	6,350	
Other	(428)	(396)
Changes in assets and liabilities related to operations:		
Accrued production receivable	(33,520)	(44,359)
Trade and other receivables	18,897	(46,879)
Other assets	(21)	269
Accounts payable and accrued liabilities	33,026	(10,442)
Oil and gas production payable	(9,574)	27,065
Other liabilities	617	(1,191)
Net cash provided by operating activites	260,789	370,329
Cash flow used for investing activities:		
Oil and natural gas capital expenditures	(215,978)	(303,654)
Acquisitions of oil and natural gas properties	(196,274)	(2,357)
Distributions from Genesis	5,115	2,725
CO_2 capital expenditures, including pipelines	(399,406)	(110,198)
Net purchases of other assets	(8,312)	(16,931)
Net proceeds from sales of oil and gas properties and equipment	240,087	49,029
Other	(72)	(686)
Net cash used for investing activities	(574,840)	(382,072)
Cash flow from financing activities:		
Bank repayments	(505,000)	(222,000)
Bank borrowings	475,000	72,000
Income tax benefit from equity awards	938	14,143
Pipeline financing Genesis	171	225,248

Issuance of subordinated debt	389,827	
Issuance of common stock	7,257	9,710
Costs of debt financing	(10,080)	
Other	(1,172)	(456)
Net cash provided by financing activities	356,941	98,645
Net increase in cash and cash equivalents	42,890	86,902
Cash and cash equivalents at beginning of period	17,069	60,107
Cash and cash equivalents at end of period	$ 59,959	$ 147,009
Supplemental disclosure of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ 5,837	$ 10,186
Cash paid (refunded) for income taxes	(14,416)	58,629
Interest capitalized	27,827	12,811
Decrease in accrual for capital expenditures	(41,612)	(5,999)

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS
(In thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net income (loss)	$ (87,240)	$ 114,053	$ (105,537)	$ 187,055
Other comprehensive income, net of income tax:				
Change in fair value of interest rate lock derivative contracts designated as a hedge, net of tax of $301 and $49, respectively		492		12
Interest rate lock derivative contracts reclassified to income, net of taxes of $10, $551, $21 and $562, respectively	17	900	35	918
Comprehensive income (loss)	$ (87,223)	$ 115,445	$ (105,502)	$ 187,985

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. Unless indicated otherwise or the context requires, the terms we, our, us, Denbury or Compa refer to Denbury Resources Inc. and its subsidiaries. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2008. Any capitalized terms used but not defined in these Notes to Unaudited Condensed Consolidated Financial Statements have the same meaning given to them in the Form 10-K.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. In management s opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments (of a normal recurring nature) necessary to present fairly the consolidated financial position of Denbury as of June 30, 2009, the consolidated results of its operations for the three and six month periods ended June 30, 2009 and 2008 and cash flows for the six months ended June 30, 2009 and 2008. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter. We have evaluated events that occurred subsequent to June 30, 2009 through August 10, 2009, the financial statement issuance date.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share is computed by dividing net income by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner but also considers the impact on net income and common shares for the potential dilution from stock options, stock appreciation rights (SARs), non-vested restricted stock and any other convertible securities outstanding. For the three and six month periods ended June 30, 2009 and 2008, there were no adjustments to net income (loss) for purposes of calculating diluted net income (loss) per common share. The following is a reconciliation of the weighted average common shares used in the basic and diluted net income (loss) per common share calculations for the three and six month periods ended June 30, 2009 and 2008.

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2009	2008	2009	2008
Weighted average common shares basic	246,084	243,623	245,830	243,189
Potentially dilutive securities:				
Stock options and SARs		7,389		8,043
Restricted stock		1,389		1,371
Weighted average common shares - diluted	246,084	252,401	245,830	252,603

The weighted average common shares basic amount excludes 2,928,022 shares at June 30, 2009 and 2,668,538 shares at June 30, 2008, of non-vested restricted stock that is subject to future vesting over time. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income (loss) per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating weighted average common shares diluted during the three and six months ended June 30, 2008, the non-vested restricted stock is included in the computation using the treasury stock method, with the proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

For the three and six months ended June 30, 2008, stock options and SARs to purchase approximately 49,000 and 691,000 shares of common stock, respectively, were outstanding but excluded from the diluted net income per common share calculations, as the exercise prices of the options exceeded the average market price of the Company s common stock during these periods and would be anti-dilutive to the calculations.

For the three and six months ended June 30, 2009, all outstanding stock options, SARs and non-vested restricted stock were excluded from the calculation of weighted average common shares - diluted as their impact would have been antidilutive to the net losses incurred during those periods. During the three and six months ended June 30, 2009, 11.2 million and 11.1 million, respectively, of stock options and SARs were excluded from the calculation of weighted average common shares - diluted and for both 2009 periods, 2.8 million shares of non-vested restricted stock were excluded.

CO_2 Pipelines

CO_2 pipelines are used for transportation of CO_2 to our tertiary floods from our CO_2 source field located near Jackson, Mississippi. We are continuing expansion of our CO_2 pipeline infrastructure with several pipelines currently under construction. At June 30, 2009 and December 31, 2008, we had $761.7 million and $402.0 million of costs, respectively, related to pipeline construction in progress, recorded under CO_2 properties, equipment and pipelines in our Unaudited Condensed Consolidated Balance Sheets. These costs of CO_2 pipelines under construction were not being depreciated at June 30, 2009 or December 31, 2008. Depreciation will commence as each pipeline is placed into service. Each pipeline is depreciated on a straight-line basis over its estimated useful life as determined for GAAP purposes, which range between 20 to 30 years.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized, but rather it is tested for impairment annually and also when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. In the case of Denbury, we have only one reporting unit. The fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

Recently Adopted Accounting Pronouncements

Business Combinations. In December 2007, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 141 (Revised 2008), Business Combinations. SFAS No. 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 noncontrolling interest in the acquiree and the goodwill acquired. SFAS No. 141(R) also establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. We adopted this statement on January 1, 2009. We have applied SFAS 141(R) to an acquisition that we made during the first quarter (see Note 2, Acquisitions and Divestitures).

Equity Method Accounting. In November 2008, the FASB reached a consensus on Emerging Issues Task Force (EITF) Issue 08-6, Equity Method Investment Accounting Considerations which was issued to clarify how the application of equity method accounting will be affected by SFAS No. 141(R) and SFAS No. 160, Non-Controlling Interests in Consolidated Financial Statements an amendment of ARB No. 51. EITF 08-6 clarifies that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirms past accounting practices related to the treatment of contingent consideration and the use of the impairment model under Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock . Additionally, it requires an equity method investor to account for a share issuance by an investee as if the investor had sold a proportionate share of the investment. This Issue was effective January 1, 2009, applies prospectively and did not have any impact on our financial position or results of operations.

Noncontrolling Interests. In December 2007, the FASB issued SFAS No. 160 which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

interest, and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS No. 160 also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted SFAS No. 160 on January 1, 2009. Since we currently do not have any noncontrolling interests, the adoption of SFAS No. 160 did not have any impact on our financial position or results of operations.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of SFAS No. 133. SFAS No. 161 requires entities that utilize derivative instruments to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit-risk-related contingent features contained within derivatives. SFAS No. 161 also requires entities to disclose additional information about the amounts and location of derivatives located within the financial statements, how the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, have been applied, and the impact that hedges have on an entity s financial position, financial performance, and cash flows. We adopted the disclosure requirement of SFAS No. 161 beginning January 1, 2009 (see Note 6, Derivative Instruments and Hedging Activities). The adoption of this statement did not have any impact on our financial position or results of operations.

Fair Value Measurements. On February 12, 2008, the FASB issued FASB Staff Position (FSP) SFAS No. 157-2 Effective Date of FASB Statement No. 157, which delayed the effective date of SFAS No. 157, Fair Value Measurements, for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We adopted FSP FASB No. 157-2 on January 1, 2009. The adoption of this FSP did not have any impact on our financial position or results of operations.

In April 2009, the FASB issued three FASB Staff Positions to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP SFAS No. 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, provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157. FSP SFAS No. 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP SFAS No. 115-2 and SFAS No. 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. These three FSPs are effective for interim and annual periods ending after June 15, 2009. The adoption of these FSPs enhanced our interim financial statement disclosures but did not have any impact on our financial position or results of operations.

Subsequent Events. In May 2009, the FASB issued SFAS No. 165, Subsequent Events to establish accounting standards for events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS No. 165 does not significantly change current practice. The new standard does require companies to disclose the date through which subsequent events were evaluated and whether or not that date was the date the financial statements were issued or available for issuance. The Company adopted SFAS No. 165 upon issuance. This standard did not have any impact on the Company s financial position or results of operations.

Recently Issued Accounting Pronouncements

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies that have an audit performed on their reserves to report the independence and qualifications of the auditor of the reserve estimates, and to file reports when a third party reserve engineer is relied upon to prepare reserve estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based upon the prior twelve-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after

December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may have on our financial condition or results of operations.

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

FASB Accounting Standards Codification™. In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles , which becomes effective for financial statements issued for interim and annual periods ending after September 15, 2009. SFAS No. 168 replaces SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles . The FASB Accounting Standards Codification ™ will become the source of U.S. GAAP recognized by the FASB for nongovernmental entities. The Company will apply this standard to our financial statements issued for the nine months ended September 30, 2009. This standard will not have any impact on the Company s financial position or results of operations.

Transfers of Financial Assets. In June 2009, the FASB issued SFAS No. 166, Accounting for Transfers of Financial Assets an amendment to FASB Statement No. 140. SFAS No. 166 removes the concept of a qualifying special-purpose entity (QSPE) from FASB Statement No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities a replacement of FASB Statement 125 , creates a new unit of account definition that must be met for transfers of portions of financial assets to be eligible for sale accounting, clarifies the derecognition criteria for a transfer to be accounted for as a sale, changes the amount of recognized gains or losses on the transfer of financial assets accounted for as a sale when beneficial interests are received by the transferor and introduces new disclosure requirements. SFAS No. 166 is effective for us beginning January 1, 2010. We do not anticipate the adoption of SFAS No. 166 will have a material impact on our financial condition or results of operations.

Consolidation of Variable Interest Entities. In June 2009, the FASB issued SFAS No. 167, Amendments to FASB Interpretation No. 46(R). This standard eliminates the exemption in FASB Interpretation No. 46(R) for QSPEs, introduces a new approach for determining who should consolidate a variable interest entity and changes the requirement as to when it is necessary to reassess who should consolidate a variable-interest entity. This standard is effective for us beginning January 1, 2010. We are currently evaluating the impact the new rule may have on our financial condition or results of operations.

Note 2. Acquisitions and Divestitures

Hastings Field Acquisition

During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc., that gave us an option to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. We exercised the purchase option prior to September 2008, and closed the acquisition during February 2009. As consideration for the option agreement, during 2006 through 2008, we made cash payments totaling $50 million which we recorded as a deposit. The purchase price of approximately $196 million, which was paid in cash, was determined as of January 1, 2009 (the effective date) with closing on February 2, 2009. The deposit plus purchase price, adjusted for interim net cash flows between the effective date and closing date of the acquisition (including minor purchase price adjustments), totaled approximately $248.2 million.

Under the terms of the agreement, Venoco, Inc., the seller, retained a 2% override and a reversionary interest of approximately 25% following payout, as defined in the option agreement. The Hastings Field proved reserves were not included in the Company s year-end 2008 proved reserves. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green Pipeline currently under construction and construction of field recycling facilities. Under the agreement, we are required to make aggregate net cumulative capital expenditures in this field of approximately $179 million over the next six years cumulating as follows: $26.8 million by December 31, 2010, $71.5 million by December 31, 2011, $107.2 million by December 31, 2012, $142.9 million by December 31, 2013, and $178.7 million by December 31, 2014. If we fail to spend the required amounts by the due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. Further, we are committed to inject at least an average of 50 MMcf/day of CO_2 (total of purchased and recycled) in the West Hastings Unit for the 90 day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to Venoco all assets previously purchased for the value of such assets at that time based upon the discounted value of the field s proved reserves using a 20% discount rate, or

(2) make an additional payment of $20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a $30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the CO_2 injection rate in the Hastings Field equals or exceeds the minimum required injection rate.

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

This acquisition of Hastings Field qualifies as a business under SFAS No. 141(R), Business Combinations. As such, we estimated the fair value of this property as of the acquisition date, as defined in SFAS No. 141(R) to be the date on which the acquirer obtains control of the acquiree, which for this acquisition is February 2, 2009 (the closing date). SFAS No. 157, Fair Value Measurements, defines fair value as 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 (often referred to as the exit price). Further, SFAS No. 157 emphasizes that a fair value measurement should be based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions should not impact the measurement of fair value unless those assumptions are consistent with market participant views.

In applying these accounting principles we estimated that the fair value of these properties on the acquisition date to be approximately $107.0 million. This measurement resulted in the recognition of goodwill totaling $138.7 million. SFAS No. 141(R) defines goodwill as an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. For this acquisition, goodwill is the excess of the cash paid to acquire the Hastings Field over the acquisition date estimated fair value. This resultant goodwill is due primarily to two factors. The first factor is the decrease in the NYMEX oil and natural gas futures prices between the effective date of January 1, 2009 and the acquisition date of February 2, 2009. The purchase agreement provided that the Hastings reserves be valued using the NYMEX oil and gas futures prices on the effective date of January 1, 2009. The second factor is the estimated fair value assigned to the estimated oil reserves recoverable through a CO_2 enhanced oil recovery (EOR) project. Denbury has one of the few known significant natural sources of CO_2 in the United States, and the largest known source east of the Mississippi river. This source of CO_2 that we own will allow Denbury to carry out CO_2 EOR activities in this field at a much lower cost than other market participants. However, SFAS No. 157 does not allow entity-specific assumptions in the measurement of fair value. Therefore, we estimated the fair value of the oil reserves recoverable through CO_2 EOR using an estimated cost of CO_2 to other market participants. This assumption of a higher cost of CO_2 resulted in an estimated fair value of the projected CO_2 EOR reserves that would not have been economically viable and therefore no value has been assigned to undeveloped properties in this acquisition.

The fair value of Hastings Field was based on significant inputs not observable in the market, which SFAS No. 157 refers to as Level 3 inputs. Key assumptions include (1) NYMEX oil and natural gas futures (this input is observable), (2) projections of the estimated quantities of oil and natural gas reserves, (3) projections of future rates of production, (4) timing and amount of future development and operating costs, (5) projected cost of CO_2 to a market participant, (6) projected recovery factors and, (7) risk adjusted discount rates. The fair value of these properties was assigned to the assets and liabilities acquired, which included $107.0 million to evaluated properties in the full cost pool and $2.4 million (net) for land, oilfield equipment and other related assets. Denbury applies SEC full cost accounting rules, under which the acquisition cost of oil and gas properties are recognized on a cost center basis (country), of which Denbury has only one cost center (United States). The goodwill of $138.7 million was assigned to this single reporting unit. All of the goodwill is deductible for tax purposes as property cost. This purchase price allocation is preliminary and subject to adjustment as the final closing statement is not complete.

The transaction related costs (legal, accounting, due diligence, etc.) have been expensed in accordance with the provisions of SFAS No. 141(R). We have not presented any pro forma information for the acquired business as the pro forma effect was not material to our results of operations for the three or six month periods ended June 30, 2009 or 2008.

Sale of Barnett Shale Assets

In May 2009, we entered into an agreement to sell 60% of our Barnett Shale natural gas assets to Talon Oil and Gas LLC, a privately held company, for $270 million (before closing adjustments). In June 2009, we closed on approximately three-quarters of the sale with net proceeds (after closing adjustments, but including the $10 million deposit) of $197.5 million. The agreement has an effective date of June 1, 2009, and consequently operating net revenues after June 1, net of capital expenditures, along with any other purchase price adjustments, were adjustments to the selling price. We did not record a gain or loss on the sale in accordance with the full cost method of accounting.

The Company closed on the remaining portion of the sale on July 15, 2009 (see Note 9, Subsequent Event). We have not presented pro forma information for the disposal as the pro forma effect was not material.

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 3. Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and CO_2 wells, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset.

The following table summarizes the changes in our asset retirement obligations for the six months ended June 30, 2009.

In thousands	Six Months Ended June 30, 2009
Balance, beginning of period	$ 45,064
Liabilities incurred and assumed during period	2,638
Revisions in estimated retirement obligations	857
Liabilities settled during period	(1,511)
Accretion expense	1,637
Sales	(838)
Balance, end of period	$ 47,847

At June 30, 2009, $1.6 million of our asset retirement obligation was classified in Accounts payable and accrued liabilities under current liabilities in our Unaudited Condensed Consolidated Balance Sheets. Liabilities incurred during the six month period ended June 30, 2009 are primarily related to the Hastings Field acquisition and sales during the period are primarily related to the Barnett Shale natural gas assets (see Note 2, Acquisitions and Divestitures). We hold cash and liquid investments in escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $7.4 million at both June 30, 2009 and December 31, 2008 and are included in Other assets in our Unaudited Condensed Consolidated Balance Sheets.

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 4. Notes Payable and Long-Term Indebtedness

In thousands	June 30, 2009	December 31, 2008
9.75% Senior Subordinated Notes due 2016	$ 426,350	$
Discount on Senior Subordinated Notes due 2016	(28,566)	
7.5% Senior Subordinated Notes due 2015	300,000	300,000
Premium on Senior Subordinated Notes due 2015	556	599
7.5% Senior Subordinated Notes due 2013	225,000	225,000
Discount on Senior Subordinated Notes due 2013	(728)	(826)
NEJD financing Genesis	172,163	173,618
Free State financing Genesis	78,260	76,634
Senior bank loan	45,000	75,000
Capital lease obligations Genesis	4,171	4,544
Capital lease obligations	2,484	2,705
Total	1,224,690	857,274
Less current obligations	4,586	4,507
Long-term debt and capital lease obligations	$ 1,220,104	$ 852,767

Issuance of 9.75% Senior Subordinated Notes due 2016

On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 (2016 Notes). The 2016 Notes, which carry a coupon rate of 9.75%, were sold at a discount (92.816% of par), which equates to an effective yield to maturity of approximately 11.25%. The net proceeds of $381.4 million were used to repay most of our then-outstanding borrowings under our bank credit facility, which increased from the December 31, 2008 balance, primarily associated with the funding of the Hastings Field acquisition (see Note 2, Acquisitions and Divestitures). In conjunction with this debt offering we amended our bank credit facility in early February 2009, which, among other things, allowed us to issue these senior subordinated notes.

In June 2009, we issued an additional $6.35 million of the 2016 Notes to our founder, Gareth Roberts, as part of a Founder s Retirement Agreement. In connection with this issuance, we recorded compensation expense of $6.35 million in General and administrative expense in our Unaudited Condensed Consolidated Statement of Operations for the three and six months ended June 30, 2009.

The 2016 Notes mature on March 1, 2016, and interest on the 2016 Notes is payable March 1 and September 1 of each year beginning on September 1, 2009. We may redeem the 2016 Notes in whole or in part at our option beginning March 1, 2013, at the following redemption prices: 104.875% after March 1, 2013, 102.4375% after March 1, 2014, and 100%, after March 1, 2015. In addition, we may at our option, redeem up to an aggregate of 35% of the 2016 Notes before March 1, 2012 at a price of 109.75%. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2016 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

Senior Bank Loan

To clarify that Denbury entities are allowed to guarantee obligations of other Denbury entities, in May 2009 we amended our Sixth Amended and Restated Credit Agreement, the instrument governing our Senior Bank Loan, to explicitly permit these guarantees and waive any possible previous technical violations of this provision.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

In June 2009 we again amended our Senior Bank Loan agreement in connection with the sale of our Barnett Shale natural gas properties and (i) reduced our borrowing base from $1.0 billion to $900 million and (ii) allowed for an additional percentage of our forecasted production to be hedged through June 30, 2009. The amendment did not impact the banks commitment amount, which remains at $750 million.

Note 5. Related Party Transactions Genesis

Interest in and Transactions with Genesis

Denbury s subsidiary, Genesis Energy, LLC, is the general partner of, and together with Denbury s other subsidiaries, owns an aggregate 12% interest in Genesis Energy, L.P. (Genesis), a publicly traded master limited partnership. Genesis business is focused on the mid-stream segment of the oil and natural gas industry in the Gulf Coast area of the United States, and its activities include gathering, marketing and transportation of crude oil and natural gas, refinery services, wholesale marketing of CO_2, and supply and logistic services.

We account for our 12% ownership in Genesis under the equity method of accounting as we have significant influence over the limited partnership; however, our control is limited under the limited partnership agreement and therefore we do not consolidate Genesis. Our investment in Genesis is included in Other assets in our Unaudited Condensed Consolidated Balance Sheets. Denbury received cash distributions from Genesis of $5.1 million and $2.8 million during the six months ended June 30, 2009 and 2008, respectively. We also received $0.1 million during both the six months ended June 30, 2009 and 2008 as directors fees for certain officers of Denbury that are board members of Genesis. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, LLC.

At June 30, 2009, the balance of our equity investment in Genesis was $78.9 million. Based on quoted market values of Genesis publicly traded limited partnership units at June 30, 2009, the estimated market value of our publicly traded common units of Genesis was approximately $51.2 million. Since the general partner units we hold are not publicly traded, there is not a readily available market value for these units. Due to the capital market conditions during the latter part of 2008 and in 2009, we have reviewed the value of our investment in Genesis as of June 30, 2009 for impairment. Based upon this review, which considered the current and future expected cash flows of Genesis, we do not believe the investment balance is impaired.

Incentive Compensation Agreement

In late December 2008, our subsidiary, Genesis Energy, LLC, entered into agreements with three members of Genesis management, for the purpose of providing them incentive compensation, which agreements make them Class B Members in Genesis Energy, LLC. The compensation agreements provide Genesis management with the ability to earn up to an approximate aggregate 17% interest in the incentive distributions that Genesis Energy, LLC receives (commencing in 2009) from Genesis. The percentage interest in the incentive distribution earned in any given period can vary based upon the Cash Available Before Reserves (CABR) per unit as generated by Genesis (excluding any transactions between Genesis and the Company) over each of the three individual s base amount of CABR per unit as stated in their compensation agreement, subject to vesting and other requirements. As the amount of CABR per unit increases, the members share of the incentive distributions increases, up to a maximum aggregate 17% in any given period.

The amount payable under the award in the event of an employee termination is the present value of the member s share of forecasted incentive distributions assuming the then current level of distributions continue into perpetuity. The award agreement dictates that the member s share of future incentive distributions be discounted back to the payment date using a discount rate equal to the current distribution yield of market comparable general partners of master limited partnerships.

The awards vest 25% on each anniversary grant date. The awards are mandatorily redeemable upon termination of employment or change in control and require the membership interests of the holders of the awards to be redeemed for cash (or in certain circumstances Genesis limited partnership units) by Genesis Energy, LLC. Under the provisions of SFAS 123(R), Share-Based Payment , the estimated fair value of these awards is measured each reporting period and recorded as a liability to the extent vested. Changes in the liability are recorded as compensation expense in General and administrative expenses in our Unaudited Condensed Consolidated Statement of Operations. We use the graded

DENBURY RESOURCES INC.
Notes to Unaudited Condensed Consolidated Financial Statements

attribution method to recognize the share-based compensation expense associated with these awards. As of June 30, 2009, we had approximately $5.3 million recorded as a liability for these awards in our Unaudited Condensed Consolidated Balance Sheet. We recorded approximately $2.9 million in the three month period ended June 30, 2009 and $2.6 million in the three month period ended March 31, 2009 in General and administrative expenses on our Unaudited Condensed Consolidated Statement of Operations, of which $0.1 million in each three month period relates to cash payments made under these awards and $2.8 million and $2.5 million, respectively, are associated with the fair value of the award.

The fair value of these awards is estimated using a discounted cash flow analysis which includes assumptions regarding a number of variables, including Genesis management s estimates of future CABR generated by Genesis, the distribution yield of market comparable publicly-traded general partners of master limited partnerships and a discount rate which considers the risk of forecasted items being realized, the time value of money and the risk of nonperformance by Denbury.

NEJD Pipeline and Free State Pipeline Transactions

On May 30, 2008, we closed on two transactions with Genesis involving our Northeast Jackson Dome (NEJD) pipeline system and Free State Pipeline, which included a long-term transportation service agreement for the Free State Pipeline and a 20-year financing lease for the NEJD system. We have recorded both of these transactions as financing leases. At June 30, 2009, we have recorded $172.2 million for the NEJD financing and $78.3 million for the Free State financing as debt, $3.1 million of which was recorded in current liabilities on our Unaudited Condensed Consolidated Balance Sheet. At December 31, 2008, we had $173.6 million for the NEJD pipeline and $76.6 million for the Free State Pipeline recorded as debt, of which $3.0 million was included in current liabilities in our Unaudited Condensed Consolidated Balance Sheet. (See Note 4, Notes Payable and Long-Term Indebtedness).

Oil Sales and Transportation Services

We utilize Genesis trucking services and common carrier pipeline to transport certain of our crude oil production to sales points where it is sold to third party purchasers. We expensed $2.0 million and $1.9 million, respectively, for these transportation services during the three months ended June 30, 2009 and 2008, respectively, and $4.2 million and $3.4 million during the six months ended June 30, 2009 and 2008, respectively.

Transportation Leases

We have pipeline transportation agreements with Genesis to transport our crude oil from certain of our fields in Southwest Mississippi, and to transport CO_2 from our main CO_2 pipeline to Brookhaven Field for our tertiary operations. We have accounted for these agreements as capital leases. At June 30, 2009 and December 31, 2008, we had $4.2 million and $4.5 million, respectively, of capital lease obligations with Genesis recorded as liabilities in our Unaudited Condensed Consolidated Balance Sheets.

CO_2 Volumetric Production Payments

During 2003 through 2005, we sold 280.5 Bcf of CO_2 to Genesis under three separate volumetric production payment agreements. We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and recognize such revenue as CO_2 is delivered under the volumetric production payments. At June 30, 2009 and December 31, 2008, $22.0 million and $24.0 million, respectively, was recorded as deferred revenue, of which $4.1 million was included in current liabilities at both June 30, 2009 and December 31, 2008. We recognized deferred revenue of $1.0 million and $1.1 million for the three month periods ended June 30, 2009 and 2008, respectively, and $2.0 million and $2.2 million during the six month periods ended June 30, 2009 and 2008, respectively, for deliveries under these volumetric production payments. We provide Genesis with certain processing and transportation services in connection with transporting CO_2 to their industrial customers for a fee of approximately $0.20 per Mcf of CO_2. For these services, we recognized revenues of $1.3 million and $1.4 million for the three months ended June 30, 2009 and 2008, respectively, and $2.5 million and $2.6 million for the six months ended June 30, 2009 and 2008, respectively.

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 6. Derivative Instruments and Hedging Activities

Oil and Natural Gas Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts and therefore the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts are shown under Commodity derivative expense in our Unaudited Condensed Consolidated Statements of Operations.

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps.

As a result of the recent economic conditions, and in order to protect our liquidity in the event that commodity prices decline, during early October 2008 we purchased oil derivative contracts for 2009 with a floor price of $75 per Bbl and a ceiling price of $115 per Bbl for total consideration of $15.5 million. In March 2009, we entered into crude oil swap contracts covering 25,000 Bbls/d for the first quarter of 2010 at a weighted average price of $51.85 per barrel, and crude oil collar contracts covering 25,000 Bbls/d for the second quarter of 2010 with a weighted average floor price of $50.00 per Bbl and a weighted average ceiling price of $74.60 per Bbl. Also during March 2009, we entered into natural gas derivative swap contracts covering 55,000 MMBtu/d for 2010 at a weighted average price of $5.66 per MMBtu, and 40,000 MMBtu/d for 2011 at a weighted average price of $6.21 per MMBtu. In May 2009, we entered into crude oil collar contracts covering 25,000 Bbls/d for the third quarter of 2010 with a weighted average floor price of $57.50 per Bbl and a weighted average ceiling price of $80.34 per Bbl. In conjunction with the sale of our Barnett Shale assets (see Note 2, Acquisitions and Divestitures), we transferred a portion of our 2010 and 2011 natural gas derivative swap contracts to the purchaser, Talon Oil and Gas LLC. At June 30, 2009, we retained natural gas derivative swap contracts covering 42,000 MMBtu/d for 2010 at an average price of $5.67 per MMBtu and 29,000 MMBtu/d for 2011 at a weighted average price of $6.23 per MMBtu.

At June 30, 2009, our oil and natural gas derivative contracts were recorded at their fair value, which was a net liability of $47.0 million. All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with parties that are lenders under our Senior Bank Loan.

The following is a summary of Commodity derivative expense included in our Unaudited Condensed Consolidated Statements of Operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2009	2008	2009	2008
Receipt (payment) on settlements of derivative contracts oil	$ 42,002	$ (12,131)	$ 127,838	$ (19,523)
Receipt (payment) on settlements of derivative contracts gas		(16,463)		(17,119)
Fair value adjustments to derivative contracts expense	(194,791)	(30,223)	(301,142)	(68,956)
Commodity derivative expense	$ (152,789)	$ (58,817)	$ (173,304)	$ (105,598)

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Fair Value of Crude Oil Derivative Contracts Not Classified as Hedging Instruments under SFAS No. 133:

	NYMEX Contract Prices Per Bbl				Estimated Fair Value Asset (Liability)	
			Collar Prices		June 30,	December 31,
Type of Contract and Period	Bbls/d	Swap Price	Floor	Ceiling	2009	2008
					(In thousands)	
Collar Contracts						
July 2009 - Dec. 2009	30,000		$75.00	$115.00	$ 39,279	$249,746
April 2010 - June 2010	5,000		50.00	76.00	(3,089)	
April 2010 - June 2010	10,000		50.00	73.15	(7,416)	
April 2010 - June 2010	5,000		50.00	76.40	(3,009)	
April 2010 - June 2010	5,000		50.00	74.30	(3,447)	
July 2010 - Sept. 2010	2,500		55.00	80.10	(1,145)	
July 2010 - Sept. 2010	10,000		55.00	80.00	(4,616)	
July 2010 - Sept. 2010	7,500		60.00	80.40	(2,588)	
July 2010 - Sept. 2010	5,000		60.00	81.05	(1,613)	
Swap Contracts						
Jan. 2010 - March 2010	6,667	$52.50			(12,369)	
Jan. 2010 - March 2010	3,333	52.20			(6,270)	
Jan. 2010 - March 2010	5,000	52.10			(9,449)	
Jan. 2010 - March 2010	5,000	50.90			(9,969)	
Jan. 2010 - March 2010	5,000	51.45			(9,731)	

Fair Value of Natural Gas Derivative Contracts Not Classified as Hedging Instruments under SFAS No. 133:

On July 15, 2009, in conjunction with closing the second portion of our sale of 60% of our Barnett Shale natural gas assets (see Note 2, Acquisitions and Divestitures) we transferred 3,000 MMBtu/d of our 2010 natural gas derivative swap contracts, and 2,000 MMBtu/d of our 2011 natural gas derivative swap contracts, to the purchaser, Talon Oil and Gas LLC.

	NYMEX Contract Prices Per MMBtu		Estimated Fair Value Asset (Liability)	
			June 30,	December 31,
Type of Contract and Period	MMBtu/d	Swap Price	2009	2008
			(In thousands)	
Swap Contracts				
Jan. 2010 - Dec. 2010	42,000	$5.67	$(5,514)	$
Jan. 2011 - Dec. 2011	10,000	6.27	(1,980)	
Jan. 2011 - Dec. 2011	10,000	6.25	(2,027)	
Jan. 2011 - Dec. 2011	9,000	6.16	(2,095)	

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Additional Disclosures about Derivative Instruments:

At June 30, 2009 and December 31, 2008, we had derivative financial instruments under SFAS No. 133 recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) June 30, 2009	December 31, 2008
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative Asset			
Crude Oil contracts	Derivative assets - current	$ 39,279	$ 249,746
Derivative Liability			
Crude Oil contracts	Derivative liability - current	(64,750)	
Natural Gas contracts	Derivative liability - current	(205)	
Crude Oil contracts	Derivative liability - long-term	(9,962)	
Natural Gas contracts	Derivative liability - long-term	(11,410)	
Total derivatives not designated as hedging instruments		$ (47,048)	$ 249,746

For the three and six months ended June 30, 2009 and 2008, the effect on income of derivative financial instruments under SFAS No. 133 was as follows:

Type of Contract	Location of Gain/(Loss) Recognized in Income	Amount of Gain / (Loss) Recognized in Income For Three Months Ended June 30, 2009	June 30, 2008	Amount of Gain / (Loss) Recognized in Income For Six Months Ended June 30, 2009	June 30, 2008
			(In thousands)		
Derivatives not designated as hedging instruments:					
Commodity Contracts					
Crude Oil Contracts	Commodity derivative expense	$ (147,316)	$ (19,688)	$ (157,341)	$ (24,442)
Natural Gas Contracts	Commodity derivative expense	(5,473)	(39,129)	(15,963)	(81,156)

Total derivatives not designated as hedging instruments	$ (152,789)	$ (58,817)	$ (173,304)	$ (105,598)

Note 7. Fair Value Measurements

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). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Level 1 Quoted prices in active markets for identical assets or liabilities as of the reporting date. During 2008 we had no level 1 recurring measurements.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Instruments in this category include non-exchange-traded oil and natural gas derivatives such as over-the-counter swaps. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts as required by SFAS No. 157. We have measured nonperformance risk based upon credit default swaps or credit spreads. At both June 30, 2009 and December 31, 2008, the fair value of our oil and natural gas derivative contracts was reduced by $3.7 million for estimated nonperformance risk.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009.

	Fair Value Measurements at June 30, 2009 Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Oil derivative contracts	$	$ 39,279	$	$ 39,279
Liabilities:				
Oil and natural gas derivative contracts		(86,327)		(86,327)
Total	$	$ (47,048)	$	$ (47,048)

The following table sets forth the fair value of financial instruments that are not recorded at fair value in our Unaudited Condensed Consolidated Financial Statements.

	June 30, 2009		December 31, 2008	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
9.75% Senior Subordinated Notes due 2016	$397,784	$438,075	$	$
7.5% Senior Subordinated Notes due 2015	300,556	285,000	300,599	213,000
7.5% Senior Subordinated Notes due 2013	224,272	214,875	224,174	171,000
Senior Bank Loan	45,000	41,128	75,000	64,000

The fair values of our senior subordinated notes are based on quoted market prices. The carrying value of our Senior Bank Loan is approximately fair value based on the fact that it is subject to short-term floating interest rates that

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

approximate the rates available to us for those periods. We adjusted the estimated fair value measurement of our Senior Bank Loan in accordance with SFAS No. 157 for estimated nonperformance risk. This estimated nonperformance risk totaled approximately $3.9 million and $11.0 million at June 30, 2009 and December 31, 2008, respectively, and was determined utilizing industry credit default swaps. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 8. Condensed Consolidating Financial Information

Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc. s subsidiaries other than minor subsidiaries, except that with respect to our $225 million of 7.5% Senior Subordinated Notes due 2013, Denbury Resources Inc. and Denbury Onshore, LLC are co-obligors. Except as noted in the foregoing sentence, Denbury Resources Inc. is the sole issuer and Denbury Onshore, LLC is a subsidiary guarantor. The results of our equity interest in Genesis are reflected through the equity method by one of our subsidiaries, Denbury Gathering & Marketing. Each subsidiary guarantor and the subsidiary co-obligor are 100% owned, directly or indirectly, by Denbury Resources Inc. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and subsidiary guarantors:

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Balance Sheets

	June 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 453,561	$ 256,901	$ 17,236	$ (466,337)	$ 261,361
Property and equipment		3,215,096	111,650		3,326,746
Investment in subsidiaries (equity method)	1,268,178		1,212,347	(2,480,525)	
Other assets	747,393	204,921	56,205	(738,028)	270,491
Total assets	$ 2,469,132	$ 3,676,918	$ 1,397,438	$ (3,684,890)	$ 3,858,598
Liabilities and Stockholders Equity					
Current liabilities	$ 15,857	$ 698,317	$ 122,762	$ (466,337)	$ 370,599
Long-term liabilities	698,340	1,766,254	6,498	(738,028)	1,733,064
Stockholders equity	1,754,935	1,212,347	1,268,178	(2,480,525)	1,754,935
Total liabilities and stockholders equity	$ 2,469,132	$ 3,676,918	$ 1,397,438	$ (3,684,890)	$ 3,858,598

	December 31, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 458,051	$ 408,940	$ 14,992	$ (466,784)	$ 415,199
Property and equipment		2,973,947	28,250		3,002,197
Investment in subsidiaries (equity method)	1,371,347		1,313,656	(2,685,003)	
Other assets	312,239	114,372	56,002	(310,335)	172,278
Total assets	$ 2,141,637	$ 3,497,259	$ 1,412,900	$ (3,462,122)	$ 3,589,674

Liabilities and Stockholders Equity					
Current liabilities	$ 970	$ 810,476	$ 41,405	$ (466,784)	$ 386,067
Long-term liabilities	300,599	1,373,127	148	(310,335)	1,363,539
Stockholders equity	1,840,068	1,313,656	1,371,347	(2,685,003)	1,840,068
Total liabilties and stockholders equity	$ 2,141,637	$ 3,497,259	$ 1,412,900	$ (3,462,122)	$ 3,589,674

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations

	Three Months Ended June 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 15,862	$ 215,538	$ 1,854	$ (15,862)	$ 217,392
Expenses	17,380	354,224	2,318	(15,862)	358,060
Income (loss) before the following:	(1,518)	(138,686)	(464)		(140,668)
Equity in net earnings of subsidiaries	(85,722)		(85,015)	170,737	
Income before income taxes	(87,240)	(138,686)	(85,479)	170,737	(140,668)
Income tax provision (benefit)		(53,671)	243		(53,428)
Net income (loss)	$ (87,240)	$ (85,015)	$ (85,722)	$ 170,737	$ (87,240)

	Three Months Ended June 30, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 5,625	$ 417,218	$ 767	$ (5,625)	$ 417,985
Expenses	5,746	233,361	828	(5,625)	234,310
Income (loss) before the following:	(121)	183,857	(61)		183,675
Equity in net earnings of subsidiaries	114,171		114,449	(228,620)	
Income before income taxes	114,050	183,857	114,388	(228,620)	183,675
Income tax provision (benefit)	(3)	69,408	217		69,622
Net income	$ 114,053	$ 114,449	$ 114,171	$ (228,620)	$ 114,053

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations (continued)

	Six Months Ended June 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 26,720	$ 387,598	$ 3,553	$ (26,720)	$ 391,151
Expenses	29,053	553,188	5,273	(26,720)	560,794
Income (loss) before the following:	(2,333)	(165,590)	(1,720)		(169,643)
Equity in net earnings of subsidiaries	(103,204)		(101,345)	204,549	
Income before income taxes	(105,537)	(165,590)	(103,065)	204,549	(169,643)
Income tax provision (benefit)		(64,245)	139		(64,106)
Net income (loss)	$ (105,537)	$ (101,345)	$ (103,204)	$ 204,549	$ (105,537)

	Six Months Ended June 30, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 11,250	$ 734,462	$ 858	$ (11,250)	$ 735,320
Expenses	11,491	433,883	1,632	(11,250)	435,756
Income (loss) before the following:	(241)	300,579	(774)		299,564
Equity in net earnings of subsidiaries	187,275		188,254	(375,529)	
Income before income taxes	187,034	300,579	187,480	(375,529)	299,564
Income tax provision (benefit)	(21)	112,325	205		112,509
Net income	$ 187,055	$ 188,254	$ 187,275	$ (375,529)	$ 187,055

Table of Contents

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Cash Flows

Denbury Resources Inc. (Parent) has no independent assets or operations. Denbury Onshore, LLC is our operating subsidiary. Cash flow activity of Denbury Resources Inc. consists of intercompany loans between Denbury Resources Inc. and Denbury Onshore, LLC to service the parent company issued debt. This intercompany cash flow activity is eliminated in consolidation. Cash flow activity of Denbury Onshore, LLC combined with the other guarantor subsidiaries is presented in our Unaudited Condensed Consolidated Statements of Cash Flows.

	Six Months Ended June 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$	$ 260,548	$ 241	$	$ 260,789
Cash flow from investing activities	(388,391)	(574,840)		388,391	(574,840)
Cash flow from financing activities	388,391	356,941		(388,391)	356,941
Net increase in cash		42,649	241		42,890
Cash, beginning of period	24	16,898	147		17,069
Cash, end of period	$ 24	$ 59,547	$ 388	$	$ 59,959

	Six Months Ended June 30, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ (10)	$ 370,325	$ 14	$	$ 370,329
Cash flow from investing activities	(23,757)	(384,797)	2,725	23,757	(382,072)
Cash flow from financing activities	23,757	98,645		(23,757)	98,645
Net increase (decrease) in cash	(10)	84,173	2,739		86,902
Cash, beginning of period	34	58,343	1,730		60,107
Cash, end of period	$ 24	$ 142,516	$ 4,469	$	$ 147,009

Note 9. Subsequent Event

On July 15, 2009, we closed the remaining balance of the sale of 60% of our Barnett Shale natural gas assets (see Note 2, Acquisitions and Divestitures). Net proceeds from the second closing were approximately $62.3 million, bringing total net proceeds of the sale to approximately $259.8 million (after closing adjustments and net of $8.1 million for natural gas swaps transferred in the sale). We did not record any gain or loss on the sale in accordance with the full cost method of accounting.

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

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 our consolidated financial statements and notes thereto contained herein and in our Form 10-K for the year ended December 31, 2008, along with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Risk Factors under Item 1A. of this report, along with Forward-Looking Information at the end of this section for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are a growing independent oil and gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi, own the largest carbon dioxide (CO_2) reserves east of the Mississippi River used for tertiary oil recovery, hold interests in the Barnett Shale play near Fort Worth, Texas, and properties onshore in Louisiana, Alabama and Southeast Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, with our most significant emphasis relating to tertiary recovery. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have three primary field offices located in Laurel, Mississippi; McComb, Mississippi; and Jackson, Mississippi.

Second Quarter Operating Highlights. During the second quarter of 2009 we recorded a net loss of $87.2 million, as compared to net income of $114.1 million in the second quarter of 2008. Included in the 2009 second quarter loss was $194.8 million ($120.8 million after tax) expensed for non-cash fair value adjustments related to our oil and natural gas derivative contracts and $10.0 million ($6.2 million after tax) expensed in conjunction with Gareth Roberts retirement as CEO of the Company under a Founder s Retirement Agreement. See further discussion regarding this Founder s Retirement Agreement under Recent Management Changes below.

For the second quarter of 2009 our oil and natural gas production averaged 52,269 BOE/d, a 13% increase over second quarter 2008 production, and a 2% decrease from production levels in the first quarter of 2009. The increase over the prior year second quarter period was primarily due to a 29% increase in our tertiary oil production, which increased to 24,092 Bbls/d in the second quarter of 2009, and production from Hastings Field which we acquired in February 2009. During the second quarter of 2009 we had our first production response from our CO_2 flood at Heidelberg Field, a little earlier than originally predicted, which averaged 250 Bbls/d for the quarter. Although our average tertiary oil production increased 1,509 Bbls/d (7%) between the first and second quarters of 2009, that increase was not enough to offset production decreases in our Barnett Shale production and non-tertiary Mississippi production. Most of the decrease in our Barnett Shale production between the first and second quarters of 2009 was associated with additional sales of natural gas liquids that were produced during the third and fourth quarters of 2008, but not sold until the first quarter of 2009 due to plant shutdowns caused by Hurricane Ike. The decrease in our non tertiary Mississippi production was primarily due to anticipated declines in our Heidelberg and Sharon Field production. See Results of Operations CO_2 Operations and Results of Operations Operating Results Production for further discussion on the changes in our production volumes.

Despite the increase in our oil and natural gas production volumes over second quarter 2008 levels, our oil and natural gas revenues were 49% lower in the second quarter of 2009 than in the prior year second quarter, as the average price we received for our production on a per BOE basis was 55% lower in the current year period. Since over 70% of our production is oil, oil prices have a much larger impact on our revenues than natural gas prices. NYMEX oil prices moved from $44.60 per barrel at December 31, 2008 to as low as $34.00 per barrel in mid-February 2009, up to $49.66 per barrel at March 31, 2009 and $69.89 per barrel at June 30, 2009. NYMEX natural gas prices have decreased from year-end 2008, falling from $5.62 per Mcf at December 31, 2008 to $3.78 per Mcf at March 31, 2009 and $3.835 per Mcf at June 30, 2009.

Cash settlements received on our oil commodity derivative contracts, which are not included in our oil and natural gas revenues, were $42.0 million in the second quarter of 2009, as compared to cash payments made of $12.1 million on oil derivative contracts and $16.5 million in cash payments on our natural gas commodity derivative contracts in the

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

second quarter of 2008. The non-cash fair value adjustments associated with our derivative contracts resulted in a $194.8 million charge in the second quarter of 2009 as compared to a $30.2 million charge in the prior year period, due primarily to the increase in oil prices and expiration of contracts during the quarter.

Our second quarter lease operating expenses on a gross basis were approximately 9% higher than in the second quarter of 2008 and approximately 12% higher than in the first quarter of 2009. On a per BOE basis, our lease operating expenses were approximately 4% lower than in the second quarter of 2008, as higher production levels offset the increase in lease operating expenses, but were approximately 13% higher than in the first quarter of 2009 as we began expensing production costs associated with two new tertiary floods in the second quarter of 2009 (Cranfield and Heidelberg Fields). Although we have focused a great deal of effort on reducing lease operating expenses in the first part of this year, the new tertiary floods, the acquisition of Hastings Field in early February 2009 (which has a significantly higher operating cost per BOE than most of the Company s other fields) and the recent increase in oil prices which results in higher CO_2 costs, negatively impacted our per BOE lease operating expenses during the quarter (see further discussion below under Results of Operations Operating Results Production Expenses).

Our general and administrative expenses were approximately $18.3 million higher than in the second quarter of 2008, due primarily to higher employee costs, the expensing of $2.9 million associated with our compensation arrangement for certain management of Genesis, and $10.0 million expensed in connection with Mr. Gareth Roberts retirement as CEO and President of the Company under a Founder s Retirement Agreement (see further discussion below under Recent Management Changes and Results of Operations General and Administrative Expenses).

Interest expense also increased in the second quarter of 2009, primarily due to higher average debt levels related to the Hastings Field acquisition in February 2009, and a higher average cost of money (i.e. higher interest rates), partially offset by higher levels of capitalized interest during the second quarter of 2009 as compared to the second quarter of 2008.

Sale of Barnett Shale Natural Gas Assets. In May 2009, we entered into an agreement to sell 60% of our Barnett Shale assets to Talon Oil and Gas LLC, a privately held company, for $270 million (before closing adjustments). On June 30, 2009, we closed on approximately three-quarters of the sale with net proceeds (after closing adjustments) of $197.5 million. The agreement has an effective date of June 1, 2009, and consequently operating net revenues after June 1, net of capital expenditures, along with any other purchase price adjustments, were adjustments to the selling price. We did not record a gain or loss on the sale in accordance with the full cost method of accounting. We closed on the remaining portion of the sale on July 15, 2009. Our net proceeds from this sale, after estimated taxes, are expected to be $235 million. We plan to use the net proceeds from the sale to currently repay bank debt, but we plan to ultimately use the net proceeds from this sale to increase our capital spending on our tertiary operations during 2010 above those levels that we would otherwise choose to spend.

Recent Management Changes. On June 30, 2009, under a management succession plan adopted by our Board of Directors and announced on February 5, 2009, Gareth Roberts, the Company s founder, relinquished his position as President and CEO and became Co-Chairman of the Board of Directors and assumed a non-officer role as the Company s Chief Strategist. Phil Rykhoek, previously Senior Vice President and Chief Financial Officer, became CEO; Tracy Evans, previously Senior Vice President Reservoir Engineering, became President and Chief Operating Officer; and Mark Allen, previously Vice President and Chief Accounting Officer, became Senior Vice President and Chief Financial Officer.

In connection with Mr. Roberts retirement as CEO and President of the Company, Mr. Roberts and the Company entered into a Founder s Retirement Agreement (the Agreement). Under this Agreement, Mr. Roberts received compensation of (i) $3.65 million in cash, plus (ii) the Company issued him $6.35 million of the Company s 9.75% Senior Subordinated Notes due 2016. As part of the Agreement, there are restrictions that prohibit Mr. Roberts from trading the Notes for two years, and he has entered into a non-compete arrangement with the Company through 2013. Mr. Roberts will continue to provide services to the Company as Co-Chairman of the Board of Directors and in a non-officer role as Chief Strategist.

Purchase of Hastings Field. On February 2, 2009, we closed the acquisition of Hastings Field located near Houston, Texas for approximately $201 million in cash. Hastings Field is a significant potential tertiary oil flood that we plan to flood with CO_2 delivered from Jackson Dome using our Green Pipeline, which is currently under construction. We originally entered into an agreement in November 2006 with a subsidiary of Venoco, Inc., that gave us the option to

DENBURY RESOURCES INC.
Management s Discussion and Analysis of Financial Condition and Results of Operations

purchase their interest in the Hastings Field. As consideration for the purchase option, we made total payments of $50 million which makes our aggregate purchase price $251 million. The seller retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the purchase agreement. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green Pipeline and construction of field recycling facilities. Under the purchase agreement, we are required to make net capital expenditures in this field totaling $179 million over the next six years, including our first obligation of $26.8 million during 2010, and are committed to begin CO_2 injections averaging 50 MMcf/d by the fourth quarter of 2012. Production from this field averaged 1,562 BOE/d during the first quarter of 2009, representing approximately two months of production, and 2,189 BOE/d during the second quarter of 2009, all non-CO_2 production.

We have recorded the acquisition of Hastings Field in accordance with SFAS No. 141(R), Business Combinations, which became effective for acquisitions after December 31, 2008. Based on these new rules, we have allocated $107.0 million of the $248.2 million adjusted purchase price to proved properties, approximately $2.4 million to land, oilfield equipment and other related assets, and the remaining $138.7 million to goodwill. See further discussion on this acquisition in Note 2 to the Unaudited Condensed Consolidated Financial Statements.

Subordinated Debt Issuance. On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 (the Notes). The Notes were sold to the public at 92.816% of par, plus accrued interest from February 13, 2009, which equates to an effective yield to maturity of approximately 11.25% (before offering expenses). Interest on the Notes will be paid on March 1 and September 1 of each year, beginning September 1, 2009. The Notes will mature on March 1, 2016. We used the net proceeds from the offering of approximately $381.4 million to repay most of the then outstanding debt on our bank credit facility. We issued an additional $6.35 million of Notes to Mr. Roberts on June 30, 2009 (see Recent Management Changes above).

Capital Resources and Liquidity

In a continuing effort to mitigate the effects of the deterioration in the capital markets and the steep decline in commodity prices which began during mid-2008, we have taken additional measures during the first half of 2009 to improve our liquidity. In February 2009, we issued $420 million of 9.75% Senior Subordination Notes and in June and July 2009, we completed the sale of 60% of our Barnett Shale assets. During the second quarter we also entered into additional commodity derivative contracts for 2010 to protect our cash flow. We used the $381.4 million proceeds from the February Notes issuance to repay the majority of our then-outstanding bank debt, and we plan to do the same with the proceeds from our recent Barnett Shale sale, at least temporarily, freeing up our credit line for future capital needs. Our new commodity derivative contracts include crude oil collars covering 25,000 Bbls/d during the third quarter of 2010 with a weighted average floor price of $57.50 per barrel and a weighted average ceiling price of $80.34 per barrel.

We currently estimate our 2009 capital spending will be approximately $750 million, plus $201 million for the already closed Hastings Field acquisition. Our current 2009 capital budget includes approximately $500 million to be spent on our CO_2 pipelines, the majority of which will be spent on the Green Pipeline. The budget also assumes that we fund approximately $100 million of budgeted equipment purchases with operating leases, which is dependent upon securing acceptable financing. Through June 30, 2009, we have completed approximately $44 million of these leases. If we do not enter into a total of $100 million of operating leases during 2009, our net capital expenditures would increase accordingly, and we would anticipate funding those additional capital expenditures under our bank credit line.

Our 2009 budget incorporates significantly reduced spending in the Barnett Shale, and in other conventional areas such as the Heidelberg Selma Chalk, and a slower development program for our tertiary operations. Based on our current cash flow projections using futures prices as of the end of July 2009, and including the expected cash settlements on our 2009 oil derivative contracts, we anticipate that our projected 2009 capital expenditures of approximately $750 million, plus our already closed $201 million Hastings acquisition could, in the aggregate, exceed projected cash flow by as much as $450 million to $550 million. We expect this shortfall to be funded by the $381.4 million of net proceeds from our February 2009 subordinated debt issuance and the estimated $235 million of net proceeds from the sale of 60% of our Barnett Shale properties; however, we ultimately expect to utilize the net proceeds from the Barnett Shale assets to increase our capital expenditures in our tertiary operations during 2010.

As part of our semi-annual bank review, on April 1, 2009 our borrowing base and commitment amount were reaffirmed at $1.0 billion and $750 million, respectively. The borrowing base represents the amount that can be borrowed

DENBURY RESOURCES INC.
Management s Discussion and Analysis of Financial Condition and Results of Operations

from a credit standpoint while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. In conjunction with the sale of our Barnett Shale properties the banks re-determined our bank borrowing base and reduced it from $1.0 billion to $900 million, but the commitment amount was left unchanged at $750 million. We anticipate this credit line will be sufficient for our 2009 plans, and do not expect our bank credit line to be reduced by our banks unless commodity prices were to decrease significantly from current levels. Based on current projections, we expect to have little or no bank debt drawn at the end of 2009, leaving up to $750 million available on our bank line.

We currently do not anticipate raising any additional capital during 2009 unless needed for an acquisition or to supplement previously budgeted equipment leasing if we are unable to find suitable financing. We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital spending up or down depending on cash flows; however, any such reduction in capital spending could reduce our anticipated production levels in future years. For 2009, we have contracted for certain capital expenditures, including construction of most of the Green Pipeline already in progress and two drilling rigs, and therefore the portion of capital that we could eliminate without significant penalty is limited (refer to Management s Discussion and Analysis of Financial Condition and Results of Operations Off-Balance Sheet Arrangements Commitments and Obligations in our 2008 Form 10-K for further information regarding these commitments).

Sources and Uses of Capital Resources

Capital Expenditure Summary

The following table of capital expenditures includes accrued capital for each period. Our cash expenditures were $41.6 million higher in the 2009 period and $6.0 million higher in the 2008 period than the amounts listed below due to the decrease in our capital accruals in those periods.

	Six Months Ended June 30,	
In thousands	2009	2008
Oil and natural gas exploration and development:		
Drilling	$ 28,960	$ 129,187
Geological, geophysical and acreage	7,198	9,475
Facilities	111,599	79,085
Recompletions	35,591	71,539
Capitalized interest	6,836	9,717
Total oil and natural gas exploration and development expenditures	190,184	299,003
Oil and gas property acquisitions	196,274	2,357
Total oil and natural gas capital expenditures	386,458	301,360
CO_2 capital expenditures		
CO_2 pipelines	340,143	47,242
CO_2 producing fields	22,453	58,514
Capitalized interest	20,991	3,094
Total CO_2 capital expenditures	383,587	108,850
Total	$ 770,045	$ 410,210

Our first half 2009 capital expenditures were funded with $260.8 million of cash flow from operations, $197.5 million of net proceeds from the sale of a portion of our Barnett Shale natural gas assets and $381.4 million of proceeds from the February 2009 issuance of 9.75% Senior Subordinated Notes. Our first half 2008 capital expenditures were

DENBURY RESOURCES INC.
Management s Discussion and Analysis of Financial Condition and Results of Operations

funded with $370.3 million of cash flow from operations, $225 million from the drop-down of CO_2 pipelines to Genesis and $48.9 million from the proceeds from the second closing on our Louisiana property sale.

Off-Balance Sheet Arrangements

Commitments and Obligations

Our obligations that are not currently recorded on our balance sheet consist of our operating leases and various obligations for development and exploratory expenditures arising from purchase agreements, our capital expenditure program, or other transactions common to our industry. In addition, in order to recover our proved undeveloped reserves, we must also fund the associated future development costs as forecasted in the proved reserve reports. Our derivative contracts are discussed in Note 6 to the Unaudited Condensed Consolidated Financial Statements.

On February 2, 2009, we closed our $201 million purchase of Hastings Field. Under the agreement, we are required to make aggregate net cumulative capital expenditures in this field of approximately $179 million over the next six years cumulating as follows: $26.8 million by December 31, 2010, $71.5 million by December 31, 2011, $107.2 million by December 31, 2012, $142.9 million by December 31, 2013, and $178.7 million by December 31, 2014. If we fail to spend the required amounts by the due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. Further, we are committed to injecting at least an average of 50 MMcf/d of CO_2 (total of purchased and recycled) in the West Hastings Unit for the 90 day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to Venoco all assets previously purchased for the value of such assets at that time based upon the discounted value of the field s proved reserves using a 20% discount rate, or (2) make an additional payment of $20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a $30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the CO_2 injection rate in the Hastings Field equals or exceeds the minimum required injection rate.

We currently have long-term commitments to purchase CO_2 from eight proposed gasification plants, four of which are in the Gulf Coast region and four in the Midwest region (Illinois, Indiana and Kentucky). The Midwest plants are not only conditioned on the specific plants being constructed, but also upon Denbury contracting additional volumes of CO_2 for purchase in the general area of the proposed plants that would provide an acceptable economic return on the CO_2 pipeline that we would need to construct to transport these volumes to our existing CO_2 pipeline system. If all of these plants were to be built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of 1.2 Bcf/d to 1.9 Bcf/d. Due to the current economic conditions, the earliest we would expect any plant to be completed and providing CO_2 would be 2013, and there is some doubt as to whether they will be constructed at all. The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent all-in cost of CO_2 from our natural source (Jackson Dome) using current oil prices. Prices for CO_2 delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions reduction credits using estimated futures prices of carbon emissions reduction credits. If all eight plants are built, the aggregate purchase obligation for this CO_2 would be around $280 million per year, assuming a $70 per barrel oil price, before any potential savings from our share of carbon emissions reduction credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants, and their construction is contingent on the satisfactory resolution of various issues, including financing. While it is likely that not every plant currently under contract will be constructed, there are several other plants under consideration that could provide CO_2 to us that would either supplement or replace some of the CO_2 volumes from the eight proposed plants for which we currently have CO_2 output purchase contracts. We are having ongoing discussions with several of these other potential sources.

Neither the amounts nor the terms of any other commitments or contingent obligations have changed significantly, from the year-end amounts reflected in our 2008 Form 10-K filed in March 2009 other than as discussed above, and other than our February 2009 subordinated debt issuance discussed in Overview Subordinated Debt Issuance . Please refer to Management s Discussion and Analysis of Financial Condition and Results of Operations Off-Balance Sheet Arrangements Commitments and Obligations contained in our 2008 Form 10-K for further information regarding our commitments and obligations.

Table of Contents

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

Results of Operations

CO_2 Operations

Our focus on CO_2 operations is becoming an ever-increasing part of our business and operations. We believe that there are significant additional oil reserves and production that can be obtained through the use of CO_2, and we have outlined certain of this potential in our 2008 annual report and other public disclosures. In addition to its long-term effect, our focus on these types of operations impacts certain trends in our current and near-term operating results. Please refer to Management s Discussion and Analysis of Financial Condition and Results of Operations and the section entitled CO_2 Operations contained in our 2008 Form 10-K for further information regarding these matters.

During 2009 we have drilled one additional CO_2 source well to further increase our production capacity and reserves at Jackson Dome. While the preliminary results are encouraging, we are not yet certain as to the magnitude of incremental reserves, if any. We estimate that we are currently capable of producing between 900 MMcf/d and 1 Bcf/d of CO_2. During the second quarter of 2009 our CO_2 production averaged 581 MMcf/d, as compared to an average of approximately 596 MMcf/d during the second quarter of 2008, and 732 MMcf/d in the first quarter of 2009. We used 87% of this production, or 499 MMcf/d, in our tertiary operations during the second quarter of 2009, and sold the balance to our industrial customers or to Genesis pursuant to our volumetric production payments.

We spent approximately $0.16 per Mcf to produce our CO_2 during the first six months of 2009, comprised of $0.14 per Mcf during the first quarter of 2009 and $0.18 per Mcf during the second quarter of 2009. This rate is down significantly from $0.25 per Mcf during the first six months of 2008, due primarily to decreased CO_2 royalty expense as a result of lower oil prices (upon which royalties are based) in the first half of 2009. Our estimated total cost per thousand cubic feet of CO_2 during the first half of 2009 was approximately $0.24, after inclusion of depreciation and amortization expense, down from the 2008 first six months average of $0.33 per Mcf. Our estimated total cost per thousand cubic feet of CO_2 during the second quarter of 2009 was approximately $0.26, after inclusion of depreciation and amortization expense.

We recently announced that we have initiated a comprehensive feasibility study of a possible long-term CO_2 pipeline project which would connect proposed gasification plants in the Midwest to the Company s existing CO_2 pipeline infrastructure in Mississippi or Louisiana. Two of the proposed plants are in the term sheet negotiation phase of a U.S. Department of Energy Loan Guarantee Program (see Off-Balance Sheet Obligations Commitment and Obligations) which would still require successful finalization of negotiations with the Department of Energy (DOE) to receive such guarantees. The Illinois Department of Commerce and Economic Opportunity has provided financial assistance for the feasibility study for the Illinois portion of the pipeline. The feasibility study is expected to determine the most likely pipeline route, the estimated costs of constructing such a pipeline, and review regulatory, legal and permitting requirements. Our current preliminary estimates suggest this would be a 500 to 700 mile pipeline system with a preliminary cost estimate of approximately $1.0 billion, based on the cost of other pipelines recently built or under construction by the Company. It is estimated that the study will be completed in the fourth quarter of 2009, following which, we will evaluate external market conditions, the potential financing opportunities and construction of the proposed gasification projects, and make a decision as to whether or not we will take initial steps to build such a pipeline.

A third proposed gasification plant for which Denbury has a CO_2 output purchase contract, was also selected by the loan guarantee program. The Company plans to commence a pipeline study for this plant proposed to be built along the Gulf Coast of Mississippi, which would likely be a 110 mile pipeline that connects to the existing Free State Pipeline.

In addition to our natural source of CO_2 and the proposed gasification plants discussed above (see Off-Balance Sheet Arrangements Commitments and Obligations), we continue to have ongoing discussions with owners of existing plants of various types that emit CO_2 which we may be able to purchase. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes at a minimum, compression and dehydration facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than the proposed gasification plants, but such volumes may still be attractive if the source is located near our Green Pipeline.

The capture of CO_2 could also be influenced by anticipated federal legislation, which could impose economic penalties for the emission of CO_2. We believe that we are a likely purchaser of CO_2 produced in our area of operations because of the scale of our tertiary operations, our CO_2 pipeline infrastructure, and our large natural source of CO_2 (Jackson Dome), which can act as a swing CO_2 source to balance CO_2 supplies and demands.

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

The following table summarizes our tertiary oil production and tertiary lease operating expense per barrel for each quarter in 2008 and the first and second quarters of 2009.

	Average Daily Production (BOE/d)					
Tertiary Oil Field	First Quarter 2008	Second Quarter 2008	Third Quarter 2008	Fourth Quarter 2008	First Quarter 2009	Second Quarter 2009
Phase I:						
Brookhaven	2,638	2,714	2,772	3,178	3,451	3,466
Little Creek area	1,807	1,661	1,556	1,706	1,619	1,560
Mallalieu area	6,099	6,260	5,339	5,056	4,490	4,264
McComb area	1,632	1,818	2,061	2,092	2,246	2,429
Lockhart Crossing			182	555	607	698
Phase II:						
Eucutta	2,699	2,933	3,262	3,538	3,813	4,145
Heidelberg						250
Martinville	793	715	736	1,213	1,118	951
Soso	1,488	1,885	2,358	2,704	2,705	2,589
Phase III:						
Tinsley		675	1,518	1,832	2,390	3,402
Phase IV:						
Cranfield					144	338
Total tertiary oil production	17,156	18,661	19,784	21,874	22,583	24,092
Tertiary operating expense per Bbl	$ 20.81	$ 24.67	$ 26.81	$ 21.86	$ 20.48	$ 20.86

Oil production from our tertiary operations increased to an average of 24,092 Bbls/d in the second quarter of 2009, a 29% increase over our second quarter 2008 tertiary production level of 18,661 Bbls/d and a 7% increase over our first quarter 2009 tertiary production level. These increases are the result of the production growth in our more recent floods such as Tinsley, Eucutta and Soso Fields, whose production has increased since the second quarter of 2008 as the CO_2 floods have been expanded and production response occurs across the fields. In addition, we had our first production response from Cranfield Field during the first quarter of 2009 and our first response from Heidelberg Field in the second quarter of 2009, a little earlier than anticipated. The recent decline at Mallalieu Field is partially due to CO_2 recycle volumes exceeding the plant capacity there. We are currenty expanding the capacity of the facility and expect it to be operational late in the third quarter of 2009. Once the recycle capacity is expanded we would expect production at Mallalieu Field to plateau. Additionally, the recent decline at Soso Field is largely due to water handling limitations that have recently been addressed and we expect production at Soso Field to increase during the fourth quarter of 2009. We now anticipate initiating CO_2 injections at Delhi Field (Phase V) during the fourth quarter of 2009. Although the Delhi pipeline is essentially complete, we are awaiting regulatory approvals before we can commission the line. We currently anticipate initial tertiary production response at Delhi Field around mid-year 2010.

During the second quarter of 2009, our operating costs for our tertiary properties averaged $20.86 per Bbl, lower than the prior year s second quarter average of $24.67 per Bbl, but slightly higher than our first quarter 2009 average of $20.48 per Bbl. For the first six months of 2009, our tertiary properties averaged $20.68 per Bbl as compared to $22.82 per Bbl in the prior year period. While our costs have increased on a gross basis due to our new tertiary floods and ongoing expansion of existing floods, they have decreased on a per Bbl basis from the second quarter and first six months of 2008, primarily due to our increased production and to the reduced cost of CO_2 in the current year periods. On a per Bbl basis, our cost of CO_2 decreased by $3.22 per BOE, from $6.90 per Bbl in the second quarter of 2008 to $3.68 in the second quarter of 2009, primarily due to the reduction in oil prices to which our CO_2 costs are partially tied. In addition, our workover costs were lower in the second quarter of 2009 on a per BOE basis than in the prior year period. The slight increase from the first quarter of 2009 on a per BOE basis is primarily due to our new floods in Cranfield and Heidelberg, where we began expensing production costs during the second quarter of 2009, and higher equipment rental costs due to new equipment leases. In addition, the cost of our CO_2 increased in the current quarter as a result

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

of higher oil prices as discussed above. For any specific field, we expect our tertiary lease operating expense per BOE to be high initially, then decrease as production increases, ultimately levelling off until production begins to decline toward the latter life of the field, when lease operating expense per BOE will again increase.

Operating Results

As summarized in the Overview section above and discussed in more detail below, our operating results for the second quarter and first six months of 2009 were significantly lower as compared to the same periods in the prior year, despite our significant production growth from the prior year. The primary factors impacting our operating results were lower oil and natural gas commodity prices in the current year periods, significant non-cash losses associated with fair value changes in our oil and natural gas derivative contracts and generally higher costs, which are explained in more detail below.

Certain of our operating results and statistics for the comparative second quarters and first six months of 2009 and 2008 are included in the following table.

Table of Contents

DENBURY RESOURCES INC.
Management s Discussion and Analysis of Financial Condition and Results of Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands except per share and unit data	2009	2008	2009	2008
Operating results				
Net income (loss)	$ (87,240)	$ 114,053	$ (105,537)	$ 187,055
Net income (loss) per common share basic	(0.35)	0.47	(0.43)	0.77
Net income (loss) per common share diluted	(0.35)	0.45	(0.43)	0.74
Cash flow from operations	148,170	164,072	260,789	370,329
Average daily production volumes				
Bbls/d	37,921	31,332	37,781	30,748
Mcf/d	86,088	89,835	90,327	89,127
BOE/d (1)	52,269	46,305	52,836	45,602
Operating revenues				
Oil sales	$ 188,170	$ 326,962	$ 321,435	$ 577,403
Natural gas sales	23,382	86,281	58,186	149,037
Total oil and natural gas sales	$ 211,552	$ 413,243	$ 379,621	$ 726,440
Oil and natural gas derivative contracts (2)				
Cash receipt (payment) on settlement of derivative contracts	$ 42,002	$ (28,594)	$ 127,838	$ (36,642)
Non-cash fair value adjustment expense	(194,791)	(30,223)	(301,142)	(68,956)
Total expense from oil and natural gas derivative contracts	$ (152,789)	$ (58,817)	$ (173,304)	$ (105,598)
Operating expenses				
Lease operating expenses	$ 83,658	$ 76,825	$ 158,608	$ 142,826
Production taxes and marketing expenses (3)	10,784	20,530	19,976	37,266
Total production expenses	$ 94,442	$ 97,355	$ 178,584	$ 180,092
Non-tertiary CO_2 operating margin				
CO_2 sales and transportation fees (4)	$ 2,884	$ 3,383	$ 6,049	$ 6,234
CO_2 operating expenses	(1,095)	(453)	(2,395)	(1,596)
Non-tertiary CO_2 operating margin	$ 1,789	$ 2,930	$ 3,654	$ 4,638
Unit prices including impact of derivative settlements (2)				

Oil price per Bbl	$ 66.70	$ 110.42	$ 65.70	$ 99.69
Gas price per Mcf	2.98	8.54	3.56	8.13
Unit prices excluding impact of derivative settlements [2]				
Oil price per Bbl	$ 54.53	$ 114.67	$ 47.00	$ 103.18
Gas price per Mcf	2.98	10.55	3.56	9.19
Oil and natural gas operating revenues and expenses per BOE [1]				
Oil and natural gas revenues	$ 44.48	$ 98.07	$ 39.70	$ 87.53
Oil and natural gas lease operating expenses	$ 17.59	$ 18.23	$ 16.59	$ 17.21
Oil and natural gas production taxes and marketing expense	2.27	4.87	2.09	4.49
Total oil and natural gas production expenses	$ 19.86	$ 23.10	$ 18.68	$ 21.70

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

(2) See also Market Risk Management below for information concerning the Company s derivative transactions.

(3) Includes Transportation expense Genesis.

(4) Includes deferred revenue of $1.0 million and $1.1 million, respectively, for the three month periods ended

June 30, 2009 and 2008, and $2.0 million and $2.2 million for the six month periods ended June 30, 2009 and 2008, respectively, associated with volumetric production payments with Genesis. Also includes transportation income from Genesis of $1.3 million and $1.4 million for the three month periods ended June 30, 2009 and 2008, respectively, and $2.5 million and $2.6 million for the six months ended June 30, 2009 and 2008, respectively.

33

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

Production: Production by area for each of the quarters of 2008 and the first and second quarters of 2009 is listed in the following table.

	Average Daily Production (BOE/d)					
Operating Area	First Quarter 2008	Second Quarter 2008	Third Quarter 2008	Fourth Quarter 2008	First Quarter 2009	Second Quarter 2009
Tertiary oil fields	17,156	18,661	19,784	21,874	22,583	24,092
Mississippi non-CO_2 floods	12,128	11,617	11,694	12,150	11,904	10,043
Texas	13,522	14,068	12,701	12,576	17,063	16,088
Onshore Louisiana	905	663	512	418	708	885
Alabama and other	1,189	1,296	1,222	1,219	1,150	1,161
Total Company	44,900	46,305	45,913	48,237	53,408	52,269

As outlined in the above table, production in the second quarter of 2009 increased 13% over second quarter 2008 production levels and 16% over production levels in the first six months of 2008. These increases were primarily due to production increases in our tertiary oil fields, our Barnett Shale production and to the acquisition of Hastings Field in February 2009. In comparing the sequential first and second quarters of 2009, our average tertiary oil production increased 1,509 Bbls/d (7%), but that increase was more than offset by production decreases in our Barnett Shale production and non-tertiary Mississippi production. The increase in our tertiary operations is discussed above under Results of Operations CO_2 Operations.

Our Texas Barnett Shale production was 13,390 BOE/d during the second quarter of 2009. This was essentially flat with second quarter 2008 production levels there, but 1,542 BOE/d less than first quarter 2009 production levels. Most of the decrease in our Barnett Shale production between the first and second quarters of 2009 was associated with additional sales of natural gas liquids that were produced during the third and fourth quarters of 2008, but not sold until the first quarter of 2009 due to plant shutdowns caused by Hurricane Ike. As a result of our curtailed drilling program in the Barnett Shale during 2009, we anticipate that our Barnett Shale production will continue to decrease throughout the year. As discussed previously, we have recently sold 60% of our interests in the Barnett Shale so our production for the remainder of 2009 will be reduced correspondingly. The acquisition of Hasting Field in February 2009 added 1,562 BOE/d during the first quarter of 2009 and 2,189 BOE/d during the second quarter of 2009 to our Texas area production.

Production in the Mississippi-non-CO_2 floods area has decreased from levels in the second quarter and first six months of 2008, as well as from first quarter 2009 levels. Most of this decrease is due to the expected gradual decline in Heidelberg Field due to depletion, and less drilling activity developing natural gas in the Selma Chalk. Our drilling activity in Sharon Field (natural gas) in the latter part of 2008 helped offset the declines in the first quarter of 2009, but production there declined in the second quarter of 2009 as we have not drilled any additional wells in this field this year.

Oil and Natural Gas Revenues: Due to the significant decrease in oil and natural gas prices between the first half of 2008 and 2009, our oil and natural gas revenues dropped sharply in the second quarter and first six months of 2009 as compared to these revenues in the same periods of 2008, offset in part by increases in production. These changes in revenues, excluding any impact of our derivative contracts, are seen in the following table:

Table of Contents

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

In thousands	Three Months Ended June 30, 2009 vs. 2008		Six Months Ended June 30, 2009 vs. 2008	
	Increase (Decrease) In Revenues	Percentage Increase (Decrease) In Revenues	Increase (Decrease) In Revenues	Percentage Increase (Decrease) In Revenues
Change in revenues due to:				
Increase in production	$ 53,226	13%	$ 110,596	15%
Decrease in commodity prices	(254,917)	(62%)	(457,415)	(63%)
Total decrease in revenues	$(201,691)	(49%)	$(346,819)	(48%)

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first and second quarters and first six month periods of 2008 and 2009:

	Three Months Ended March 31,			Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	% Change	2009	2008	% Change	2009	2008	% Change
Net Realized Prices:									
Oil price per Bbl	$39.34	$91.24	(57%)	$54.53	$114.67	(52%)	$47.00	$103.18	(54%)
Gas price per Mcf	4.09	7.80	(48%)	2.98	10.55	(72%)	3.56	9.19	(61%)
Price per BOE	34.97	76.65	(54%)	44.48	98.07	(55%)	39.70	87.53	(55%)
NYMEX Differentials:									
Oil per Bbl	$ (3.99)	$ (6.50)	(39%)	$ (5.30)	$ (9.64)	(45%)	$ (4.62)	$ (7.85)	(41%)
Natural Gas per Mcf	(0.41)	(0.92)	(55%)	(0.82)	(0.92)	(11%)	(0.59)	(0.91)	(35%)

Our Company-wide oil price NYMEX differential improved in the second quarter and first six months of 2009 over our differential in the comparable prior year periods, due primarily to the decrease in oil prices. Our oil price NYMEX differential was slightly worse in the second quarter of 2009, as compared to the previous quarter, due primarily to oil price increases.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be quite large, these differentials are very seldom more than a dollar above or below NYMEX prices.

Oil and Natural Gas Derivative Contracts: The following tables summarize the impact that our oil and natural gas derivative contracts had on our operating results for the three and six months ended June 30, 2009 and 2008.

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

In thousands	Three Months Ended March 31, 2009 Non-Cash Fair Value Adjustment Income/ (expense)	Three Months Ended March 31, 2009 Cash Settlements Receipt/ (payment)	Three Months Ended June 30, 2009 Non-Cash Fair Value Adjustment Income/ (expense)	Three Months Ended June 30, 2009 Cash Settlements Receipt/ (payment)	Six Months Ended June 30, 2009 Non-Cash Fair Value Adjustment Income/ (expense)	Six Months Ended June 30, 2009 Cash Settlements Receipt/ (payment)
Crude oil derivatives:						
2009 contracts	$ (77,014)	$85,836	$(133,453)	$ 42,002	$(210,467)	$127,838
2010 contracts	(18,847)		(55,865)		(74,712)	
Total crude oil derivative contracts	$ (95,861)	$85,836	$(189,318)	$ 42,002	$(285,179)	$127,838
Natural gas derivatives:						
2010 contracts	$ (4,750)	$	$ (2,551)	$	$ (7,301)	$
2011 contracts	(5,740)		(2,922)		(8,662)	
Total natural gas derivative contracts	$ (10,490)	$	$ (5,473)	$	$ (15,963)	$
Total derivative contracts	$(106,351)	$85,836	$(194,791)	$ 42,002	$(301,142)	$127,838

In thousands	Three Months Ended March 31, 2008 Non-Cash Fair Value Adjustment Income/ (expense)	Three Months Ended March 31, 2008 Cash Settlements Receipt/ (payment)	Three Months Ended June 30, 2008 Non-Cash Fair Value Adjustment Income/ (expense)	Three Months Ended June 30, 2008 Cash Settlements Receipt/ (payment)	Six Months Ended June 30, 2008 Non-Cash Fair Value Adjustment Income/ (expense)	Six Months Ended June 30, 2008 Cash Settlements Receipt/ (payment)
Crude oil derivatives:						
2008 contracts	$ 2,638	$ (7,392)	$ (7,557)	$(12,131)	$ (4,919)	$ (19,523)
Total crude oil derivative contracts	$ 2,638	$ (7,392)	$ (7,557)	$(12,131)	$ (4,919)	$ (19,523)
Natural gas derivatives:						

2008 contracts	$ (41,371)	$ (656)	$ (22,666)	$(16,463)	$ (64,037)	$ (17,119)
Total natural gas derivative contracts	$ (41,371)	$ (656)	$ (22,666)	$(16,463)	$ (64,037)	$ (17,119)
Total derivative contracts	$ (38,733)	$ (8,048)	$ (30,223)	$(28,594)	$ (68,956)	$ (36,642)

The change in commodity prices and the expiration of contracts cause fluctuations in the mark-to-market value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the changes in fair value of these contracts are recognized currently in the income statement. During the second quarter of 2009, we recognized total non-cash fair value expense of $194.8 million and for the first half of 2009, we recognized total non-cash fair value expense of $301.1 million. Of these amounts, $133.5 million in the second quarter and $210.5 million in the first six months of 2009 related to our 2009 oil collars, partially reversing the $242.2 million gain we recognized on these collars during the fourth quarter of 2008. The remaining non-cash fair value expense recognized during the second quarter and first half of 2009 was made up of charges on the oil derivative contracts we entered into during 2009 and on our natural gas swaps (see Note 6 to the Unaudited Condensed Consolidated Financial Statements for a summary of our oil and natural gas derivative contracts.) During the second quarter and first half of 2008, we recognized non-cash fair value expense of $30.3 million and $69.0 million, respectively, on our oil and natural gas derivative contracts.

Table of Contents

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

During the second quarter and first half of 2009, we received cash settlements of $42.0 million and $127.8 million on our derivative contracts. During the second quarter and first half of 2008, we made cash payments of $28.6 million and $36.6 million on our derivative contracts, giving us a total change between the two six-month periods of $164.4 million.

Production Expenses: Our lease operating expenses increased between the comparable second quarters and first six months of 2009 versus 2008 on a gross basis as a result of (i) our increasing emphasis on tertiary operations and additional tertiary fields moving into the productive phase (see discussion of those expenses under CO_2 Operations above), (ii) the acquisition of Hastings Field in February 2009, (iii) increased personnel and related costs, (iv) higher electrical costs to operate our properties and (v) increasing lease payments for certain equipment in our tertiary operating facilities, offset in part by lower CO_2 costs due primarily to lower oil prices in the 2009 periods. Our lease operating expenses decreased on a per BOE basis between the comparable second quarters and first six months of 2009 versus 2008 due in part to the 13% and 16% increases in production, respectively, and in part to lower oil and natural gas prices, which has helped to lower the cost for certain goods and services and has reduced our cost for CO_2 (see Results of Operations CO_2 Operations for a more detailed discussion). We expect our tertiary operating costs to partially correlate with oil prices, as the price we pay for CO_2 is partially tied to oil prices. Our operating costs have increased during the last few years as oil prices have increased and the demand for goods and services has steadily risen, but with the recent drop in oil prices, we expect that lower demand for certain goods and services will gradually cause prices for those items to decrease or stabilize over time. During the second quarter of 2009, Company-wide lease operating costs averaged $17.59 per BOE, up from $15.59 per BOE during the first quarter of 2009, primarily due to the fact that our incremental growth in production quarter-over-quarter was primarily from higher cost producing properties such as our tertiary operations and a full quarter of Hastings Field production. On a proforma basis, after adjusting our second quarter 2009 operating results to remove 60% of our Barnett Shale production and lease operating expense, Company-wide lease operating expense for the second quarter of 2009 would have been approximately $19.90 per BOE.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes, and therefore were lower in the 2009 periods compared to the 2008 periods, because the severe decrease in commodity prices more than offset our increase in production. Transportation and plant processing fees were approximately $0.9 million lower in the second quarter of 2009 than in the second quarter of 2008 and approximately the same in the respective first halves of 2009 and 2008.

General and Administrative Expenses

General and administrative (G&A) expenses increased 124% between the respective second quarters and 81% between the respective first six months of 2009 and 2008 as set forth below:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2009	2008	2009	2008
Gross cash G&A expense	$ 36,107	$ 29,909	$ 71,474	$ 59,577
Employee stock-based compensation	6,359	3,962	12,499	8,459
Founder s compensation award	10,000		10,000	
Incentive compensation for Genesis management	2,945		5,538	
State franchise taxes	1,124	857	2,239	1,685
Operator labor and overhead recovery charges	(19,791)	(16,808)	(38,777)	(32,761)
Capitalized exploration and development costs	(3,609)	(3,109)	(7,183)	(6,144)
Net G&A expense	$ 33,135	$ 14,811	$ 55,790	$ 30,816

G&A per BOE:

Net cash G&A expense	$	2.88	$	2.55	$	2.87	$	2.70
Net stock-based compensation		1.13		0.76		1.10		0.81
Founder s compensation award		2.10				1.05		
Incentive compensation for Genesis management		0.62				0.58		
State franchise tax		0.24		0.20		0.23		0.20
Net G&A expense	$	6.97	$	3.51	$	5.83	$	3.71
Employees as of June 30		859		761		859		761

Gross G&A expenses increased $6.2 million, or 21%, between the respective second quarters and $11.9 million, or 20%, between the respective first six months. Approximately $5.1 million of the increase in gross G&A expenses

Table of Contents

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

between the respective quarters, and $9.7 million between the first six month periods, related to increases in compensation and personnel related costs, due primarily to the increase in employees and salary increases, which we consider necessary in order to remain competitive in our industry. During 2008, we increased our employee count by 16% and we further increased our employee count by approximately 8% during the first half of 2009. Stock compensation expense increased to $6.4 million during the second quarter of 2009 from $4.0 million for the second quarter of 2008, due primarily to the increase in employees and changes in the mix of compensation awarded to employees. On a six month basis, stock compensation was approximately $12.5 million for the first half of 2009 and $8.5 million for the first half of 2008. As discussed above in Overview Recent Management Changes, we also expensed $10 million in the second quarter of 2009 related to a Founder s Retirement Agreement for Gareth Roberts as he retired as CEO and President of the Company on June 30, 2009.

Also adding to the increase in net G&A expense for the 2009 periods was a charge relating to incentive compensation awards for the management of Genesis of $2.9 million in the second quarter of 2009 and $2.6 million in the first quarter of 2009. As incentive compensation for Genesis management, our subsidiary which is the general partner of Genesis Energy, LP, awarded management the right to earn an interest in the incentive distributions we receive. These awards are subject to vesting over four years and achieving future levels of cash available before reserves on a per unit basis, among other conditions. Based on current estimates of fair value under the provisions of SFAS 123(R), we would anticipate accruing up to $10.7 million for these awards in 2009. The annual expense is currently expected to be less in future years, although it will fluctuate based on future performance and other market conditions. See Note 5, Related Party Transactions - Genesis to the Unaudited Condensed Consolidated Financial Statements for further information regarding these incentive compensation awards.

The increase in gross G&A was offset in part by an increase in operator overhead recovery charges in the second quarter and first six months of 2009. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells from acquisitions, additional tertiary operations, drilling activity during the past year and increased compensation expense, the amount we recovered as operator overhead charges increased by 18% between the second quarters of 2008 and 2009 and increased by 18% between the first six months of 2008 and 2009. Capitalized exploration and development costs also increased by 16% between the second quarters of 2008 and 2009 and increased by 17% between the first six months of 2008 and 2009, primarily as a result of increases in personnel and compensation costs.

The net effect was a 124% increase in net G&A expense between the respective second quarters and an 81% increase between the first six months of 2009 and 2008. On a per BOE basis, G&A costs also increased, although at a lower percentage rate as a result of higher production, increasing 99% in the second quarter of 2009 as compared to levels in the second quarter of 2008, and 57% when comparing the first six months of 2009 to the prior year period.

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

Interest and Financing Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per BOE data and interest rates	2009	2008	2009	2008
Cash interest expense	$ 28,318	$ 13,278	$ 51,602	$ 25,078
Non-cash interest expense	2,040	408	3,326	815
Less: Capitalized interest	(15,454)	(5,545)	(27,827)	(12,811)
Interest expense	$ 14,904	$ 8,141	$ 27,101	$ 13,082
Interest and other income	$ 2,956	$ 1,359	$ 5,481	$ 2,646
Net cash interest expense and other income per BOE (1)	$ 2.52	$ 1.79	$ 2.33	$ 1.34
Average debt outstanding	$ 1,363,007	$ 698,475	$ 1,249,030	$ 680,142
Average interest rate (2)	8.3%	7.6%	8.3%	7.4%

(1) Cash interest expense less capitalized interest less interest and other income on BOE basis.

(2) Includes commitment fees but excludes debt issue costs and amortization of discount and premium.

Interest expense increased $6.8 million, or 83%, comparing the second quarters of 2008 and 2009, and $14.0 million, or 107%, comparing levels in the first six months of 2008 and 2009, primarily as a result of higher average debt levels resulting from the Hastings Field acquisition in early February 2009 and incremental borrowings to fund our development program. In addition, our average interest rate is higher in the current year periods than in the prior year periods as a result of the two pipeline dropdown transactions with Genesis mid-2008, which were recorded as financing leases and carry a higher imputed rate of interest, and the February 2009 issuance of $420 million of 9.75% Senior Subordinated Notes. The increase in our interest expense attributable to higher debt and interest costs was offset in part by an increase in capitalized interest in the 2009 periods, primarily due to capital expenditures on our CO_2 pipeline projects currently in progress and higher average interest rates during the periods.

Depletion, Depreciation and Amortization

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per BOE data	2009	2008	2009	2008
	$ 53,504	$ 47,820	$ 106,955	$ 92,010

Depletion and depreciation of oil and natural gas properties				
Depletion and depreciation of CO_2 assets	4,019	3,604	8,561	6,626
Asset retirement obligations	810	762	1,637	1,524
Depreciation of other fixed assets	3,362	2,547	6,467	4,412
Total DD&A	$ 61,695	$ 54,733	$ 123,620	$ 104,572
DD&A per BOE:				
Oil and natural gas properties	$ 11.42	$ 11.53	$ 11.36	$ 11.27
CO_2 assets and other fixed assets	1.55	1.46	1.57	1.33
Total DD&A cost per BOE	$ 12.97	$ 12.99	$ 12.93	$ 12.60

Our depletion, depreciation and amortization (DD&A) rate for oil and natural gas properties on a per BOE basis remained relatively constant between the respective periods. In the second quarter of 2009, we booked approximately 10.9 million barrels of incremental oil reserves related to our tertiary operations at Cranfield Field, as a result of the oil production response to the CO_2 injections in that field. Correspondingly, we moved approximately $82.4 million from unevaluated properties to the full cost pool relating to Cranfield, representing the acquisition costs and development expenditures incurred on the field prior to recognizing proved reserves.

39

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

We continually evaluate the performance of our other tertiary projects, and if performance indicates that we are reasonably certain of recovering additional reserves from these floods, we recognize those incremental reserves in that quarter. Since we adjust our DD&A rate each quarter based on any changes in our estimates of oil and natural gas reserves and costs, our DD&A rate could change significantly in the future. We currently do not anticipate that any significant incremental reserves will be recognized in the balance of 2009 as we do not expect any production from any other new floods before year-end.

Our DD&A rate for our CO_2 and other fixed assets increased in the second quarter of 2009 as compared to the rate in the comparable quarter of 2008, primarily as a result of the Delta (Jackson Dome to Tinsley) and Heidelberg CO_2 pipelines being placed into service during 2008, and due to the expansion of our corporate office space, also during 2008. At June 30, 2009, we had $761.7 million of costs related to CO_2 pipelines under construction. These costs were not being depreciated at June 30, 2009. Depreciation of these pipelines will commence as each pipeline is placed into service.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a ceiling test write-down at March 31, 2009 or June 30, 2009, as oil prices have recovered from levels at the end of 2008. However, if oil prices were to decrease significantly in subsequent periods, we may be required to record additional write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend upon oil and natural gas prices at the end of each period, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, and additional capital spent.

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per BOE amounts and tax rates	2009	2008	2009	2008
Current income tax expense	$ 24,127	$ 10,844	$ 24,300	$ 32,080
Deferred income tax expense (benefit)	(77,555)	58,778	(88,406)	80,429
Total income tax expense (benefit)	$ (53,428)	$ 69,622	$ (64,106)	$ 112,509
Average income tax expense (benefit) per BOE	$ (11.23)	$ 16.52	$ (6.70)	$ 13.56
Effective tax rate	38.0%	37.9%	37.8%	37.6%

Our income tax provision was based on an estimated statutory rate of approximately 38%. Our effective tax rate has generally been slightly lower than our estimated statutory rate due to the impact of certain items such as our domestic production activities deduction, offset in part by compensation arising from certain equity compensation that cannot be deducted for tax purposes in the same manner as book expense. In the second quarters and first six months of both years, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits. In addition, included in the second quarter of 2009 is approximately $16 million in current taxes associated with our sale of a portion of our Barnett Shale assets on June 30, 2009. In total, we expect to pay approximately $25 million in cash taxes related to this sale, with the remaining $9 million to be recorded in the third quarter upon completion of the sale. As of December 31, 2008, we had an estimated $44 million of enhanced oil recovery credits to carry forward that we can utilize to reduce our current income taxes during 2009 or future years.

In the second quarter of 2008 we obtained approval from the IRS to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. Although the overall effects of this accounting change are still under audit, we expect to receive tax refunds of approximately $10.6 million for tax years through 2007, along with other deferred tax benefits, and in the second quarter of 2008 we reduced our current income tax expense by approximately $19 million to adjust for the impact of this change through the first six months of 2008. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. Although this change is not expected to have a significant impact on the Company s overall tax rate, it is anticipated that it could defer the amount of cash taxes the Company might otherwise pay over the next several years.

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

Per BOE Data

The following table summarizes our cash flow, DD&A and results of operations on a per BOE basis for the comparative periods. Each of the individual components is discussed above.

	Three Months Ended June 30,		Six Months Ended June 30,	
Per BOE data	2009	2008	2009	2008
Oil and natural gas revenues	$ 44.48	$ 98.07	$ 39.70	$ 87.53
Gain (loss) on settlements of derivative contracts	8.83	(6.79)	13.36	(4.42)
Lease operating expenses	(17.59)	(18.23)	(16.59)	(17.21)
Production taxes and marketing expenses	(2.27)	(4.87)	(2.09)	(4.49)
Production netback	33.45	68.18	34.38	61.41
Non-tertiary CO_2 operating margin	0.38	0.70	0.38	0.56
General and administrative expenses	(6.97)	(3.51)	(5.83)	(3.71)
Net cash interest expense and other income	(2.52)	(1.79)	(2.33)	(1.34)
Current income taxes and other	(1.59)	(2.08)	(0.32)	(3.20)
Changes in assets and liabilities relating to operations	8.40	(22.56)	0.99	(9.10)
Cash flow from operations	31.15	38.94	27.27	44.62
DD&A	(12.97)	(12.99)	(12.93)	(12.60)
Deferred income taxes	16.31	(13.95)	9.24	(9.69)
Non-cash commodity derivative adjustments	(40.95)	(7.17)	(31.49)	(8.31)
Changes in assets and liabilities and other non-cash items	(11.88)	22.24	(3.13)	8.52
Net income (loss)	$ (18.34)	$ 27.07	$ (11.04)	$ 22.54

Market Risk Management

Debt

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. We had $45 million of bank debt outstanding as of June 30, 2009. The carrying value of our bank debt is approximately fair value based on the fact that it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We adjusted the estimated fair value measurements of our bank debt at June 30, 2009, for estimated nonperformance risk in accordance with SFAS No. 157. This estimated nonperformance risk totaled approximately $3.9 million and was determined utilizing industry credit default swaps. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease with Genesis (see Note 5, Related Party Transactions Genesis to our Unaudited Condensed Consolidated Balance Sheets) in the event of significant downgrades of our corporate credit rating by the rating agencies, Genesis can require certain credit enhancements from us, and possibly other remedies under the lease. The fair value of the subordinated debt is based on quoted market prices. The following table presents the carrying and fair values of our debt, along with average interest rates at June 30, 2009.

	Expected Maturity Dates				Carrying	Fair
In thousands	2011	2013	2015	2016	Value	Value
Variable rate debt:						

Bank debt (weighted average interest rate of 0.3% at June 30, 2009)	$45,000	$	$	$	$ 45,000	$ 41,128
Fixed rate debt:						
7.5% subordinated debt due 2013 (fixed rate of 7.5%)		225,000			224,271	214,875
7.5% subordinated debt due 2015 (fixed rate of 7.5%)			300,000		300,556	285,000
9.75% subordinated debt due 2016 (fixed rate of 9.75%)				426,350	397,784	438,075

Table of Contents

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

Oil and Gas Derivative Contracts

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. Recently, we have employed a strategy to hedge a portion of our production looking out 12 to 15 months from each quarter, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current world-wide economic uncertainties. See Note 6 to the Unaudited Condensed Consolidated Financial Statements for details regarding our derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with parties that are lenders under our Senior Bank Loan. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts as required by SFAS No. 157. We have measured nonperformance risk based upon credit default swaps or credit spreads. At both June 30, 2009 and December 31, 2008, the fair value of our oil and natural gas derivative contracts was reduced by $3.7 million for estimated nonperformance risk.

For accounting purposes, we do not apply hedge accounting to our oil and natural gas derivative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings. Information regarding our current derivative contract positions and results of our historical derivative activity is included in Note 6 to the Unaudited Condensed Consolidated Financial Statements.

At June 30, 2009, our derivative contracts were recorded at their fair value, which was a net liability of approximately $47.0 million, a significant change from the $249.7 million fair value asset recorded at December 31, 2008. This change is primarily related to the expiration of oil derivative contracts during the first half of 2009, and to the oil and natural gas futures prices as of June 30, 2009 in relation to the new commodity derivative contracts for 2010 and 2011 that we entered into during the first and second quarters of 2009.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil and natural gas futures prices as of June 30, 2009, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as seen in the following table:

Table of Contents

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

In thousands	Crude Oil Derivative Contracts Receipt/ (Payment)	Natural Gas Derivative Contracts Receipt/ (Payment)
Based on:		
NYMEX futures prices as of June 30, 2009	$(33,063)	$(13,012)
10% increase in prices	(85,692)	(29,588)
10% decrease in prices	24,865	3,566

Critical Accounting Policies

For a discussion of our critical accounting policies, which are related to property, plant and equipment, depletion and depreciation, oil and natural gas reserves, asset retirement obligations, income taxes and hedging activities, and which remain unchanged, except as listed below, see Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2008.

Fair Value Estimates

SFAS No. 157, Fair Value Measurements defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 7 to the Unaudited Condensed Consolidated Financial Statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions,
- assessment of impairment of long-lived assets,
- assessment of impairment of goodwill, and
- recorded value of derivative instruments.

Acquisitions

Under the acquisition method of accounting for business combinations in SFAS No. 141(R), the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. SFAS No. 141(R) defines the acquisition date as the date on which the acquirer obtains control of the acquiree, which is usually a date different than the date the economics of the acquisition are established between the acquirer and the acquiree. SFAS No. 157 defines fair value as 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 (often referred to as the exit price). Further, SFAS No. 157 emphasizes that a fair value measurement should be based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions should not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values involving property, plant and equipment and identifiable intangible assets. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Impairment Assessment of Goodwill

Goodwill must be tested for impairment at least annually, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The need to test for impairment can be based on several indicators, including a significant reduction in prices of oil or natural gas, a full-cost ceiling write-down of oil and natural gas properties, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment.

Goodwill is tested for impairment at the reporting unit level. Denbury applies SEC full-cost accounting rules, under which the acquisition cost of oil and gas properties are recognized on a cost center basis (country), of which Denbury has only one cost center (United States). Goodwill is assigned to this single reporting unit.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. A significant amount of judgment is involved performing these fair value estimates for goodwill since the results are based on forecasted assumptions. Significant assumptions include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves, and risk adjusted discount rates. We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from those projections.

Forward-Looking Information

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in this Management s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon or expected reserve quantities and values, potential reserves from tertiary operations, hydrocarbon prices, pricing assumptions based upon current and projected oil and gas prices, liquidity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our tertiary operations and future plans. Such forward-looking statements generally are accompanied by words such as plan, estimate, expect, predict, anticipate, projected, should, assume, believe, target convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management s current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company s financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company s oil and natural gas, inaccurate cost estimates, fluctuations in the prices of goods and services, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital or its availability, general economic conditions, competition and government regulations, unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or which are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company s other public reports, filings and public statements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The information required by Item 3 is set forth under Market Risk Management in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Table of Contents

DENBURY RESOURCES INC.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer. Our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting There have been no changes in the Company s internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

Information with respect to this item has been incorporated by reference from our Form 10-K for the year ended December 31, 2008. There have been no material developments in such legal proceedings since the filing of such Form 10-K.

Item 1.A. Risk Factors

Information with respect to the risk factors has been incorporated by reference from Item 1.A. of our Form 10-K for the year ended December 31, 2008. There have been no material changes to the risk factors since the filing of such Form 10-K, other than as described below.

A three judge panel has been named in an American Arbitration Association proceeding in Dallas, Texas, initiated by Denbury in late 2008 against Crosstex CCNG Processing Ltd. (Crosstex Processing) seeking damages (currently plead at the level of $11.4 million) related to a contract which provided for Crosstex Processing to process natural gas produced from Denbury s Barnett Shale field, and a counterclaim by Crosstex North Texas Gathering, L.P. (Crosstex Gathering) for $40.0 million of damages for the value of natural gas liquids to which Crosstex Gathering alleges it is entitled under a gas gathering agreement with Denbury in the same field. The parties are currently engaged in discovery in this proceeding, which is currently set for hearing in late 2009. Denbury believes that Crosstex Gathering s counterclaim is without merit, and does not believe that the ultimate resolution of these claims and counterclaims will have any material adverse effect upon it or its financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plan Or Programs
April 1 through 30, 2009	215	$16.48		
May 1 through 31, 2009				
June 1 through 30, 2009	396	$17.63		
Total	611	$17.23		

These shares were purchased from employees of Denbury who delivered shares to the company to satisfy their minimum tax withholding requirements related to the vesting of restricted shares.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

Denbury s Annual Meeting of Stockholders was held on May 13, 2009 for the purposes of (1) electing eight directors, each to serve until their successor is elected and qualified; (2) to increase the number the number of shares that may be issued under our 2004 Omnibus Stock and Incentive Plan by 7,500,000 shares; (3) to increase the number of

DENBURY RESOURCES INC.

shares that may be issued under our Employee Stock Purchase Plan by 1,500,000 shares and to extend the term of the Plan to August 2014; and (4) to ratify the appointment by the audit committee of PricewaterhouseCoopers LLP as the Company s independent registered accountants for 2009. Holders of 228,702,424 shares of common stock, representing approximately 92% of the total issued and outstanding shares of common stock were present in person or by proxy at the meeting to cast their vote.

With respect to the election of directors, all eight nominees were elected. All of the directors are elected on an annual basis. The votes were cast as follows:

Nominees for Directors	For	Withheld
Ronald G. Greene	226,426,062	2,276,362
Michael L. Beatty	227,329,645	1,372,779
Michael B. Decker	218,369,864	10,332,560
David I. Heather	227,697,430	1,004,994
Greg McMichael	216,716,641	11,985,783
Gareth Roberts	227,100,722	1,601,702
Randy Stein	227,589,429	1,112,995
Wieland F. Wettstein	215,442,237	13,260,187

The proposal to increase the number of shares that may be used under our 2004 Omnibus Stock and Incentive Plan was approved. The votes were cast as follows:

For	Against	Abstentions	Broker Non-Votes
142,567,500	72,825,615	62,313	-0-

The proposal to increase the number of shares that may be used under our Employee Stock Purchase Plan and extend the term of the plan was approved. The votes were cast as follows:

For	Against	Abstentions	Broker Non-Votes
164,372,075	51,020,838	62,515	-0-

The appointment by the audit committee of PricewaterhouseCoopers LLP as the Company s independent auditor for 2009 was approved. The votes were cast as follows:

For	Against	Abstentions	Broker Non-Votes
227,529,718	188,880	983,821	-0-

Item 5. Other Information

None.

Item 6. Exhibits

Exhibits:

10(a)*	Amendment to Sixth Amended and Restated Credit Agreement dated as of June 8, 2009.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following financial statements from the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, formatted in XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Comprehensive Operations.

* Filed 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.

DENBURY RESOURCES INC.
(Registrant)

By: /s/ Mark C. Allen

Mark C. Allen
Sr. Vice President and Chief Financial Officer

By: /s/ Alan Rhoades

Alan Rhoades
Vice President, Accounting

Date: August 10, 2009