DENBURY RESOURCES INC
Form 10-Q
August 08, 2011

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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, 2011

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission file number:001-12935
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.)
5320 Legacy Drive Plano, TX	**75024**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: **(972) 673-2000**
Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 (Do not check if a smaller reporting company)	Smaller reporting company o

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

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 August 1, 2011
Common Stock, $.001 par value	402,350,295

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DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except par value and share data)

	June 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 121,792	$ 381,869
Accrued production receivable	255,034	223,584
Trade and other receivables, net of allowance of $486 and $456, respectively	153,018	114,149
Short-term investments	88,220	93,020
Derivative assets	19,322	24,242
Deferred tax assets	22,097	27,454
Total current assets	659,483	864,318
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	6,508,928	6,042,442
Unevaluated	952,452	870,130
CO_2 and other non-hydrocarbon gases properties	572,957	523,423
Pipelines and plants	1,445,214	1,378,239
Other property and equipment	138,671	120,641
Less accumulated depletion, depreciation, amortization, and impairment	(2,403,741)	(2,197,517)
Net property and equipment	7,214,481	6,737,358
Derivative assets	17,609	12,919
Goodwill	1,232,418	1,232,418
Other assets	215,432	218,050
Total assets	$ 9,339,423	$ 9,065,063
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 333,953	$ 345,998
Oil and gas production payable	172,837	143,145
Derivative liabilities	81,627	78,184
Current maturities of long-term debt	8,622	7,948
Other liabilities	4,070	4,070
Total current liabilities	601,109	579,345
Long-term liabilities		

Long-term debt, net of current portion	2,288,112	2,416,208
Asset retirement obligations	86,109	81,290
Derivative liabilities	3,378	29,687
Deferred taxes	1,687,839	1,547,992
Other liabilities	24,562	29,834
Total long-term liabilities	4,090,000	4,105,011
Commitments and contingencies (Note 7)		
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; 402,508,885 and 400,291,033 shares issued, respectively	403	400
Paid-in capital in excess of par	3,074,335	3,045,937
Retained earnings	1,581,198	1,336,142
Accumulated other comprehensive loss	(3,429)	(488)
Treasury stock, at cost, 193,177 and 78,524 shares, respectively	(4,193)	(1,284)
Total stockholders equity	4,648,314	4,380,707
Total liabilities and stockholders equity	$ 9,339,423	$ 9,065,063

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Revenues and other income				
Oil, natural gas, and related product sales	$ 591,099	$ 488,028	$ 1,097,291	$ 818,914
CO_2 sales and transportation fees	5,343	4,690	10,267	9,187
Gain on sale of interests in Genesis		(28)		101,540
Interest income and other income	4,955	4,520	8,004	6,390
Total revenues and other income	601,397	497,210	1,115,562	936,031
Expenses				
Lease operating expenses	129,932	127,743	257,029	223,963
Production taxes and marketing expenses	39,688	38,100	72,439	57,417
CO_2 discovery and operating expenses	1,869	1,681	4,023	3,049
General and administrative	30,900	31,192	74,746	63,901
Interest, net of amounts capitalized of $13,194, $23,850, $24,151 and $45,162, respectively	42,249	43,483	91,026	69,899
Depletion, depreciation, and amortization	103,495	129,209	197,089	211,081
Derivatives income	(172,904)	(128,674)	(2,154)	(169,899)
Loss on early extinguishment of debt	348		16,131	
Transaction and other costs related to the Encore Merger	2,018	22,784	4,377	67,783
Total expenses	177,595	265,518	714,706	527,194
Income before income taxes	423,802	231,692	400,856	408,837
Income tax provision				
Current income taxes	12,028	6,941	11,180	7,610
Deferred income taxes	152,528	74,422	144,620	150,694
Consolidated net income	259,246	150,329	245,056	250,533
Less: net income attributable to noncontrolling interest		(14,962)		(18,278)
Net income attributable to Denbury stockholders	$ 259,246	$ 135,367	$ 245,056	$ 232,255
Net income per common share				
Basic	$ 0.65	$ 0.34	$ 0.62	$ 0.67

Diluted	$ 0.64	$ 0.34	$ 0.61	$ 0.66
Weighted average common shares outstanding				
Basic	398,631	395,548	398,032	345,126
Diluted	403,919	400,867	403,703	350,326

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash flows from operating activities		
Consolidated net income	$ 245,056	$ 250,533
Adjustments needed to reconcile to net cash provided by operating activities		
Depletion, depreciation, and amortization	197,089	211,081
Deferred income taxes	144,620	150,694
Gain on sale of interests in Genesis		(101,540)
Stock-based compensation	18,132	17,130
Non-cash fair value derivative adjustments	(11,508)	(226,899)
Loss on early extinguishment of debt	16,131	
Other, net	5,755	5,871
Changes in operating assets and liabilities		
Accrued production receivable	(35,068)	52,075
Trade and other receivables	(28,258)	10,058
Other assets	(2,920)	(3,134)
Accounts payable and accrued liabilities	(48,471)	12,066
Oil and natural gas production payable	30,135	11,236
Other liabilities	(7,340)	(4,880)
Net cash provided by operating activities	523,353	384,291
Cash flows used for investing activities		
Oil and natural gas capital expenditures	(471,601)	(317,173)
Acquisitions of oil and natural gas properties	(32,482)	(24,243)
Cash paid in Encore Merger, net of cash acquired		(801,489)
CO_2 and other non-hydrocarbon gases capital expenditures	(31,731)	(44,274)
Pipelines and plants capital expenditures	(98,669)	(108,177)
Net proceeds from sales of oil and natural gas properties and equipment		881,344
Net proceeds from sale of interests in Genesis		162,622
Other	1,643	(7,224)
Net cash used for investing activities	(632,840)	(258,614)
Cash flows from financing activities		
Bank repayments	(130,000)	(1,514,000)
Bank borrowings	130,000	1,149,000
Repayment of senior subordinated notes	(525,000)	(609,424)
Premium paid on repayment of senior subordinated notes	(13,137)	(7,214)
Net proceeds from issuance of senior subordinated notes	400,000	1,000,000
Net proceeds from issuance of common stock	9,203	5,540
Costs of debt financing	(13,274)	(76,232)

ENP distributions to noncontrolling interest		(12,209)
Other	(8,382)	(14,255)
Net cash used for financing activities	(150,590)	(78,794)
Net increase (decrease) in cash and cash equivalents	(260,077)	46,883
Cash and cash equivalents at beginning of period	381,869	20,591
Cash and cash equivalents at end of period	$ 121,792	$ 67,474

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Consolidated net income	$ 259,246	$ 150,329	$ 245,056	$ 250,533
Other comprehensive income, net of income tax				
Net unrealized loss on available-for-sale securities, net of tax of $(4,375) and $(1,824), respectively	(7,139)		(2,976)	
Interest rate lock derivative contracts reclassified to income, net of tax of $10, $10, $21, and $21, respectively	18	17	35	34
Change in deferred hedge loss on interest rate swaps, net of tax of $8 and $18, respectively		(60)		(87)
Consolidated comprehensive income	252,125	150,286	242,115	250,480
Less: comprehensive income attributable to noncontrolling interest		(14,950)		(18,235)
Comprehensive income attributable to Denbury stockholders	$ 252,125	$ 135,336	$ 242,115	$ 232,245

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

We are a growing independent oil and natural gas company. We are the largest oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis on our CO_2 tertiary recovery operations.

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission (SEC) and do not include all of the information and footnotes required by Accounting Principles Generally Accepted in the United States (U.S. GAAP) for complete financial statements. 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, 2010. Unless indicated otherwise or the context requires, the terms we, our, us, or Denbury, refer to Denbury Resources Inc. and its subsidiaries.

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 year. In management s opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of June 30, 2011, our consolidated results of operations for the three and six months ended June 30, 2011 and 2010, and our consolidated cash flows for the six months ended June 30, 2011 and 2010. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter.

Noncontrolling Interest

From March 9, 2010 to December 31, 2010, we owned approximately 46% of Encore Energy Partners LP (ENP) outstanding common units and 100% of Encore Energy Partners GP LLC (GP LLC), which was ENP s general partner. Considering the presumption of control of GP LLC in accordance with the *Consolidation* topic of the Financial Accounting Standards Board Codification (FASC), the results of operations and cash flows of ENP were consolidated with those of Denbury for this period. On December 31, 2010, we sold all of our ownership interests in ENP and, therefore, we did not consolidate ENP in our Unaudited Condensed Consolidated Balance Sheets as of December 31, 2010 and June 30, 2011, nor do our Unaudited Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2011 or our Unaudited Condensed Consolidated Statement of Cash Flows for the six months ended June 30, 2011 include ENP s results of operations or cash flows. As presented in the Unaudited Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2010, Net income attributable to noncontrolling interest of $15.0 million and $18.3 million, respectively, represents ENP s results of operations attributable to third-party ENP limited partner interest owners, other than Denbury, for the portion of that period for which we consolidated ENP.

Net Income Per Common Share

Basic net income per common share is computed by dividing net income attributable to our stockholders 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 of the potential dilution from stock options, stock appreciation rights (SARs), unvested restricted stock, and unvested performance equity awards. For the three and six months ended June 30, 2011 and 2010, there were no adjustments to net income attributable to our stockholders for purposes of calculating diluted net income per common share. The following is a reconciliation of the weighted average common shares used in the basic and diluted net income per common share calculations for the periods indicated:

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Notes to Unaudited Condensed Consolidated Financial Statements

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2011	2010	2011	2010
Basic weighted average common shares	398,631	395,548	398,032	345,126
Potentially dilutive securities:				
Stock options and SARs	3,946	3,980	4,251	3,835
Performance equity awards	23	146	12	312
Restricted stock	1,319	1,193	1,408	1,053
Diluted weighted average common shares	403,919	400,867	403,703	350,326

Basic weighted average common shares excludes 3.4 million and 3.6 million shares for the three and six months ended ended June 30, 2011, respectively, and 3.5 million and 3.3 million shares for the three and six months ended June 30, 2010, respectively, of unvested restricted stock. As these restricted shares vest or become retirement eligible, they will be included in the shares outstanding used to calculate basic net income per common share, although all restricted stock is issued and outstanding upon grant. For purposes of calculating diluted weighted average common shares, unvested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

The following securities could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income per share as their effect would have been anti-dilutive:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2011	2010	2011	2010
Stock options and SARs	2,412	4,223	2,297	4,785
Restricted stock	24	35	15	413

Short-term Investments

Short-term investments are available-for-sale securities recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. At June 30, 2011 and December 31, 2010, short-term investments consisted entirely of our investment in Vanguard Natural Resources LLC (Vanguard) common units obtained as partial consideration for the sale of our interests in ENP to a subsidiary of Vanguard on December 31, 2010. The cost basis of this investment is $93.0 million. We received distributions of $1.7 million and $3.5 million on the Vanguard common units we own for the three and six months ended June 30, 2011, respectively, which distributions are included in Interest income and other income on our Unaudited Condensed Consolidated Statements of Operations. The unrealized loss on our short-term investment of $7.1 million (net of a tax benefit of $4.4 million) and $3.0 million (net of a tax benefit of $1.8 million) for the three and six months ended June 30, 2011, respectively, is included in our Unaudited Condensed Consolidated Statements of Comprehensive Operations.

Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*, (ASU 2011-04). ASU 2011-04 amends the FASC *Fair Value Measurements* topic by providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the fair value disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 will be effective for our fiscal year beginning

January 1, 2012. The adoption of ASU 2011-04 is not expected to have a material effect on our consolidated financial statements, but may require additional disclosures.

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Notes to Unaudited Condensed Consolidated Financial Statements

In June 2011, the FASB issued ASU 2011-05, *Presentation of Comprehensive Income*, (ASU 2011-05). ASU 2011-05 requires the presentation of comprehensive income in either 1) a continuous statement of comprehensive income or 2) two separate but consecutive statements. ASU 2011-05 will be effective for our fiscal year beginning January 1, 2012. Since ASU 2011-05 will only amend presentation requirements, it will not have a material effect on our consolidated financial statements.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 2. Acquisitions and Divestitures

2010 Merger with Encore Acquisition Company

On March 9, 2010, we acquired Encore Acquisition Company (Encore) pursuant to the Encore Merger Agreement entered into with Encore on October 31, 2009. The Encore Merger Agreement provided for a stock and cash transaction valued at approximately $4.8 billion at the acquisition date, including the assumption of debt and the value of the noncontrolling interest in ENP (the Encore Merger). Under the Encore Merger Agreement, Encore was merged with and into Denbury, with Denbury surviving the Encore Merger.

For the three months ended June 30, 2010 and for the period from March 9, 2010 to June 30, 2010, we recognized $200.6 million and $260.9 million, respectively, of oil, natural gas sales and related product sales related to the Encore Merger. For the three months ended June 30, 2010 and for the period from March 9, 2010 to June 30, 2010, we recognized $137.8 million and $180.7 million, respectively, of net field operating income (oil, natural gas and related product sales less lease operating expenses, production taxes and marketing expenses) related to the Encore Merger. We recognized a total of $2.0 million and $22.8 million of transaction and other costs related to the Encore Merger (primarily advisory, legal, accounting, due diligence, integration and severance costs) for the three months ended June 30, 2011 and 2010, respectively, and $4.4 million and $67.8 million of such costs for the six months ended June 30, 2011 and 2010, respectively.

2010 Acquisition of Reserves in Rocky Mountain Region at Riley Ridge

In October 2010, we acquired a 42.5% non-operated working interest in the Riley Ridge Federal Unit (Riley Ridge), located in the LaBarge Field of southwestern Wyoming, for $132.3 million after closing adjustments. Riley Ridge contains natural gas resources, as well as helium and CO_2 resources. The purchase included a working interest in a gas plant, which is currently under construction, which will separate the helium and natural gas from the commingled gas stream. The acquisition also included approximately 33% of the CO_2 mineral rights in an additional 28,000 acres adjoining the Riley Ridge Unit.

This acquisition meets the definition of a business under the FASC *Business Combinations* topic. The following table presents a summary of the preliminary fair value of these Riley Ridge assets acquired and liabilities assumed:

In thousands	
Oil and natural gas properties	$ 19,646
CO_2 and other non-hydrocarbon gases properties	10,907
Pipelines and plants	72,070
Prepaid construction and drilling costs	9,346
Other assets	19,300
Asset retirement obligations	(472)
Goodwill	1,460
Total	$ 132,257

On August 1, 2011, we acquired the remaining working interest in Riley Ridge and an additional interest in the adjoining acreage and became the operator of both projects; see Note 8, *Subsequent Event*, for more information.

Pro Forma Information

Had the Encore Merger and October 2010 Riley Ridge acquisition both occurred on January 1, 2010, our combined pro forma revenues and net income for the three and six months ended June 30, 2010, would have been as follows:

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

	Pro Forma Results	
In thousands, except per share amounts	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Pro forma total revenues	$ 497,210	$ 1,112,481
Pro forma net income attributable to Denbury stockholders	135,494	247,423
Pro forma net income per common share:		
Basic	$ 0.34	$ 0.63
Diluted	0.34	0.62

2010 Sale of Interests in Genesis

In February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis Energy, L.P. (Genesis), for net proceeds of approximately $84 million. In March 2010, we sold all of our Genesis common units in a secondary public offering for net proceeds of approximately $79 million. We recognized a pre-tax gain of approximately $101.5 million ($63.0 million after tax) on these dispositions.

2010 Sale of Southern Assets

In May 2010, we sold certain non-strategic legacy Encore properties primarily located in the Permian Basin, the Mid-continent area and the East Texas Basin (the Southern Assets) to Quantum Resources Management, LLC for consideration of $892.1 million after closing adjustments. We did not record a gain or loss on the sale in accordance with the full cost method of accounting.

Note 3. Long-Term Debt

The following table shows the components of our long-term debt:

In thousands	June 30, 2011	December 31, 2010
Bank Credit Agreement	$	$
7 1/2% Senior Subordinated Notes due 2013, including discount of $437		224,563
7 1/2% Senior Subordinated Notes due 2015, including premium of $427		300,427
9 1/2% Senior Subordinated Notes due 2016, including premium of $13,222 and $14,589, respectively	238,142	239,509
9 3/4% Senior Subordinated Notes due 2016, including discount of $19,996 and $22,139, respectively	406,354	404,211
8 1/4% Senior Subordinated Notes due 2020	996,273	996,273
6 % Senior Subordinated Notes due 2021	400,000	
Other Subordinated Notes, including premium of $37 and $41, respectively	3,842	3,848
NEJD financing	165,550	167,331
Free State financing	80,953	81,188
Capital lease obligations	5,620	6,806
Total	2,296,734	2,424,156
Less current obligations	(8,622)	(7,948)
Long-term debt and capital lease obligations	$ 2,288,112	$ 2,416,208

The parent company, Denbury Resources Inc. (DRI), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. All of our 100% owned subsidiaries, other than minor subsidiaries, fully and unconditionally guarantee our senior subordinated debt jointly and severally.

Bank Credit Agreement

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders as party thereto (the Bank Credit Agreement). Availability under the Bank Credit Agreement is subject to a borrowing base which is redetermined semi-annually on or prior to May 1 and November 1 and upon requested special redeterminations. The borrowing base is adjusted at the banks discretion and is based in part upon external factors over which we have no control. If the borrowing base were to be less than outstanding borrowings under the Bank Credit Agreement, we would be required to repay the deficit over a period of four months.

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Notes to Unaudited Condensed Consolidated Financial Statements

In May 2011, we entered into the Fifth Amendment to the Bank Credit Agreement (the Amendment). The Amendment reconfirms our current borrowing base of $1.6 billion, extends the maturity of the Bank Credit Agreement from March 2014 to May 2016, reduces the applicable margin on outstanding borrowings, reduces the letter of credit fee and adjusts the maximum permitted ratio of debt to adjusted EBITDA. Under the Amendment, the margin on outstanding Eurodollar loans bears interest at the Eurodollar rate (as defined in the Bank Credit Agreement) plus the applicable margin of 1.5% to 2.5% (previously 2.0% to 3.0%) based on the ratio of outstanding borrowings to the borrowing base, and the base rate loans bear interest at the base rate (as defined in the Bank Credit Agreement) plus the applicable margin of 0.5% to 1.5% (previously 1.0% to 1.5%) based on the ratio of outstanding borrowings to the borrowing base. The Amendment also prescribes a commitment fee ranging between 0.375% and 0.5% on the unused portion of the credit facility or if less, the borrowing base, and adjusts the maximum permitted ratio of debt to adjusted EBITDA of Denbury and its subsidiaries from 4.0x to 4.25x.

6 % Senior Subordinated Notes due 2021

In February 2011, we issued $400 million of 6 % Senior Subordinated Notes due 2021 (2021 Notes). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393 million were used to repurchase a portion of our outstanding 2013 Notes and 2015 Notes (see *Redemption of our 2013 and 2015 Notes* below).

The 2021 Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year, beginning August 15, 2011. We may redeem the 2021 Notes in whole or in part at our option beginning August 15, 2016 at the following redemption prices: 103.188% on or after August 15, 2016; 102.125% on or after August 15, 2017; 101.062% on or after August 15, 2018; and 100% on or after August 15, 2019. Prior to August 15, 2014, we may, at our option, redeem up to an aggregate of 35% of the principal amount of the 2021 Notes at a price of 106.375% with the proceeds of certain equity offerings. In addition, at any time prior to August 15, 2016, we may redeem 100% of the principal amount of the 2021 Notes at a price equal to 100% of the principal amount plus a make-whole premium and accrued and unpaid interest. 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 2021 Notes are not subject to any sinking fund requirements. All of our subsidiaries, other than minor subsidiaries, fully and unconditionally guarantee this debt jointly and severally.

Redemption of our 2013 and 2015 Notes

On February 3, 2011, we commenced cash tender offers to purchase all $225.0 million principal amount of our 2013 Notes and all $300.0 million principal amount of our 2015 Notes. Upon expiration of the tender offers on March 3, 2011, we accepted for purchase $169.6 million in principal of the 2013 Notes at 100.625% of par, and $220.9 million in principal of the 2015 Notes at 104.125% of par. We called the remaining 2013 and 2015 Notes, repurchasing all of the remaining outstanding 2015 Notes ($79.1 million) at 103.75% of par on March 21, 2011 and all of the remaining outstanding 2013 Notes ($55.4 million) at par on April 1, 2011. We recognized a $0.3 million and $16.1 million loss during the three and six months ended June 30, 2011 associated with the debt repurchases, which is included in our Unaudited Condensed Consolidated Statements of Operations under the caption Loss on early extinguishment of debt .

Note 4. 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 Derivatives expense (income) in our Unaudited Condensed Consolidated Statements of Operations.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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. We currently employ a strategy to hedge a portion of our forecasted production for a period generally ranging from approximately 12 to 18 months in advance, 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 worldwide economic uncertainties and commodity price volatility.

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 commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement.

The following is a summary of Derivatives expense (income) included in the accompanying Unaudited Condensed Consolidated Statements of Operations for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2011	2010	2011	2010
Oil				
Payment on settlements of derivative contracts	$ 16,972	$ 13,829	$ 22,000	$ 77,379
Fair value adjustments to derivative contracts expense (income)	(187,194)	(145,099)	(20,130)	(206,920)
Total derivative expense (income) oil	(170,222)	(131,270)	1,870	(129,541)
Natural Gas				
Receipt on settlements of derivative contracts	(6,030)	(16,630)	(12,646)	(20,379)
Fair value adjustments to derivative contracts expense (income)	3,348	19,909	8,622	(19,109)
Total derivative expense (income) natural gas	(2,682)	3,279	(4,024)	(39,488)
Ineffectiveness on interest rate swaps		(683)		(870)
Derivative income	$ (172,904)	$ (128,674)	$ (2,154)	$ (169,899)

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Commodity Derivative Contracts Not Classified as Hedging Instruments

The following tables present outstanding commodity derivative contracts with respect to future production as of June 30, 2011:

				NYMEX Contract Prices Per Bbl		
				Weighted Average Price		
Year	Months	Type of Contract	Bbls/d	Swap	Floor	Ceiling
Oil Contracts						
2011	July - Sept	Swap	625	79.18		
		Collar	42,500		70.35	100.09
		Put	6,625		69.53	
		Total July - Sept 2011	49,750			
	Oct - Dec	Swap	625	79.18		
		Collar	45,500		70.33	101.74
		Put	6,625		69.53	
		Total Oct - Dec 2011	52,750			
2012	Jan - Mar	Swap	625	81.04		
		Collar	52,000		70.00	106.86
		Put	625		65.00	
		Total Jan - Mar 2012	53,250			
	Apr-June	Swap	625	81.04		
		Collar	53,000		70.00	119.44
		Put	625		65.00	
			54,250			

	Total Apr - June 2012					
July-Sept	Swap	625	81.04			
	Collar	53,000			80.00	128.57
	Put	625			65.00	
	Total July - Sept 2012	54,250				
Oct - Dec	Swap	625	81.04			
	Collar	53,000			80.00	128.57
	Put	625			65.00	
	Total Oct - Dec 2012	54,250				

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DENBURY RESOURCES INC.
Notes to Unaudited Condensed Consolidated Financial Statements

Year	Months	Type of Contract	MMBtu/d	Weighted Average Swap Price per MMBtu
Natural Gas Contracts				
2011	July - Sept	Swap	33,500	$ 6.27
		Total July-Sept 2011	33,500	
	Oct - Dec	Swap	33,500	6.27
		Total Oct - Dec 2011	33,500	
2012	Jan - Dec	Swap	20,000	6.53
		Total Jan - Dec 2012	20,000	

Additional Disclosures about Derivative Instruments

At June 30, 2011 and December 31, 2010, we had derivative financial instruments recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) June 30, 2011	Estimated Fair Value Asset (Liability) December 31, 2010
		(In thousands)	
Derivatives not designated as hedging instruments			
Derivative asset			
Oil contracts	Derivative assets current	$ 1,462	$ 3,050
Natural gas contracts	Derivative assets current	17,860	21,192
Oil contracts	Derivative assets long-term	11,281	1,301
Natural gas contracts	Derivative assets long-term	6,328	11,618

Derivative liability			
Oil contracts	Derivative liabilities current	(67,196)	(55,256)
Deferred premiums	Derivative liabilities current	(14,431)	(22,928)
Oil contracts	Derivative liabilities long-term	(2,228)	(25,906)
Deferred premiums	Derivative liabilities long-term	(1,150)	(3,781)
Total derivatives not designated as hedging instruments		$ (48,074)	$ (70,710)

Note 5. Fair Value Measurements

Fair Value Hierarchy

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. The FASC 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 are as follows:

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Notes to Unaudited Condensed Consolidated Financial Statements

Level 1 Quoted prices in active markets for identical assets or liabilities as of the reporting date.

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 that are based on NYMEX pricing.

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. Instruments in this category include non-exchange-traded natural gas derivatives swaps that are based on regional pricing other than NYMEX (e.g., Houston Ship Channel).

We adjust the valuations for nonperformance risk, using our estimate of the counterparty s credit quality for asset positions and Denbury s credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

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 the periods indicated:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
June 30, 2011				
Assets				
Short-term investments	$ 88,220	$	$	$ 88,220
Oil and natural gas derivative contracts		30,293	6,638	36,931
Liabilities				
Oil and natural gas derivative contracts		(69,424)		(69,424)
Total	$ 88,220	$ (39,131)	$ 6,638	$ 55,727
December 31, 2010				
Assets				
Short-term investments	$ 93,020	$	$	$ 93,020
Oil and natural gas derivative contracts		20,683	16,478	37,161
Liabilities				
Oil and natural gas derivative contracts		(81,162)		(81,162)

Total	$ 93,020	$ (60,479)	$ 16,478	$ 49,019

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

The following table summarizes the changes in the fair value of our Level 3 assets for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2011	2010	2011	2010
Balance, beginning of period	$ 15,346	$ 50,518	$ 16,478	$
Unrealized gains/(losses) on commodity derivative contracts included in earnings	(7,386)	126	(7,076)	14,899
Commodity derivative contracts acquired from Encore				38,093
Receipts on settlement of commodity derivative contracts	(1,322)	(10,361)	(2,764)	(12,709)
Balance, end of period	6,638	40,283	$ 6,638	$ 40,283

Since we do not use hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in Derivatives income in the accompanying Unaudited Condensed Consolidated Statements of Operations.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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, 2011		December 31, 2010	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
7^{1}/2% Senior Subordinated Notes due 2013	$	$	$ 224,563	$ 228,375
7^{1}/2% Senior Subordinated Notes due 2015			300,427	310,500
9^{1}/2% Senior Subordinated Notes due 2016	238,142	249,942	239,509	249,661
9^{3}/4% Senior Subordinated Notes due 2016	406,354	476,446	404,211	475,380
8^{1}/4% Senior Subordinated Notes due 2020	996,273	1,085,938	996,273	1,080,956
6 % Senior Subordinated Notes due 2021	400,000	400,000		

The fair values of our senior subordinated notes are based on quoted market prices. We have other financial instruments consisting primarily of cash, cash equivalents and short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 6. Supplemental Information

Accounts Payable and Accrued Liabilities

The following table summarizes our accounts payable and accrued liabilities as of the periods indicated:

In thousands	June 30, 2011	December 31, 2010
Accounts payable	$ 72,830	$ 47,660
Accrued exploration and development costs	96,910	101,758
Accrued compensation	26,760	39,757
Accrued lease operating expense	25,100	23,557
Accrued interest	61,166	57,077
Taxes payable	16,537	34,371
Other	34,650	41,818
Total	$ 333,953	$ 345,998

Supplemental Cash Flow Information

The following table sets forth supplemental cash flow information for the periods indicated:

	Six Months Ended June 30,	
In thousands	2011	2010
Cash paid for interest, expensed	$ 72,774	$ 43,296
Cash paid for interest, capitalized	24,151	45,162
Cash paid for income taxes	31,072	11,920
Cash received for income tax refunds	20,841	13,093
Increase in liabilities for capital expenditures	25,141	46,170
Issuance of Denbury common stock in connection with the Encore Merger		2,085,681

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 7. Commitments and Contingencies

In March 2011, we entered into three long-term supply contracts to purchase CO_2 from future anthropogenic sources in the Gulf Coast and Rocky Mountain regions. The three contracts are in addition to the previously disclosed long-term supply contracts Denbury currently has in place in the Gulf Coast, Rocky Mountain and Midwest regions. Under the three new contracts, Denbury will purchase 100% of the CO_2 captured from the DKRW Advanced Fuels LLC s Medicine Bow Fuel and Power LLC (MBFP) project in Medicine Bow, Wyoming, purchase 70% of the CO_2 captured from Mississippi Power Company s Kemper County Integrated Gasification Combined Cycle (IGCC) project in Mississippi, and purchase 100% of the CO_2 captured by Air Products LLC (Air Products) at a third-party refinery in Port Arthur, Texas. These new contracts each have an initial term of 15 to 16 years and include options to extend the term. We estimate that these new sources will supply approximately 365 MMcf/d of CO_2 for our enhanced oil recovery operations, although under certain circumstances, we may be obligated to purchase up to 460 MMcf/d, a portion of which would be at a reduced price per Mcf. We expect to begin taking delivery of approximately 200 MMCF/d of CO_2 from the MBFP project in 2015, 115 MMcf/d of CO_2 from the IGCC project by 2014, and 50 MMcf/d of CO_2 from Air Products in late 2012. Our aggregate maximum purchase obligation for CO_2 purchased under these three contracts would be approximately $110 million per year (assuming purchases of 460 MMcf/d), plus transportation, assuming a $100 per barrel NYMEX oil price. The purchase price of CO_2 will fluctuate based on the changes in the price of oil.

As is the case with all of our long-term supply contracts to purchase CO_2, the three agreements entered into in March are subject to various contingencies. The IGCC and Air Products plants are currently being constructed and MBFP is in the initial stages of construction but its completion is still contingent upon securing debt financing and equity commitments and receipt of all necessary consents and approvals.

In the third quarter of 2008, we obtained approval from the National Office of the Internal Revenue Service (IRS) to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. As a result of the approved change in method of tax accounting, beginning with the 2007 tax year we began to deduct, rather than capitalize, such costs for tax purposes, and applied for tax refunds associated with such change for our 2004 and 2006 tax years. Notwithstanding its consent to our change in tax accounting in 2008, the IRS subsequently exercised its prerogative to challenge the tax accounting method we used. In late January 2011, we received a Technical Advice Memorandum (TAM) issued by the IRS National Office disapproving our method of accounting and revoking its consent to our change, on a prospective basis only, commencing January 1, 2011. As a result of the prospective nature of the IRS s determination, there should be no change in our position with respect to the deductibility of these costs for 2007, 2008, 2009 and 2010. However, refund claims of $10.6 million for tax years through 2006 are pending and are subject to review by the Joint Committee on Taxation of the U.S. Congress. We are unable to assess the outcome of any such review, nor how that outcome may affect the other years covered by the TAM.

We are subject to audits for sales and use taxes and severance taxes in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. We have received a $15.0 million assessment from the Mississippi taxing authority for use tax, penalties and interest covering the 2004-2007 period. We believe this assessment is significantly in excess of any amounts owed and we are appealing the assessment. We do not believe the outcome of this matter will have a material adverse effect on our financial position or results of operations.

We are involved in various lawsuits, claims and other regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Note 8. Subsequent Event

On August 1, 2011, we acquired the remaining 57.5% working interest in Riley Ridge and a working interest of approximately 33% in the 28,000 acres adjacent to Riley Ridge. As a result of the transaction, we became the operator of both projects. The purchase price was approximately $191 million, including a $15 million contingent payment to be paid at the time the property s gas processing facility is operational and meets specific performance conditions, plus customary closing adjustments including payment for capital expenditures incurred between the effective date of the purchase (April 1, 2011) and closing. We expect the gas processing facility to be operational during the fourth quarter of 2011.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

The acquisition of Riley Ridge meets the definition of a business under the FASC *Business Combinations* topic. We will account for our acquisition of Riley Ridge under the acquisition method of accounting, which will result in the allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values at the date of acquisition, with the excess purchase price, if any, being recognized as goodwill. We have not yet completed our initial calculation necessary to make this allocation.

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 Annual Report on Form 10-K for the year ended December 31, 2010, 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 natural gas company. We are the largest oil and natural gas producer in both Mississippi and Montana, own the largest CO_2 reserves used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis on our CO_2 tertiary recovery operations.

The acquisition of Encore Acquisition Company (the Encore Merger) on March 9, 2010, has had a significant impact on nearly every aspect of our business, including oil and natural gas production, revenues and operating expenses. Accordingly, the Encore Merger impacts the comparability of our financial results for the first six months of 2010 to those in the first six months of 2011, which is more fully detailed throughout the following discussion and analysis. Our financial results for the first six months of 2010 include the results of operations of Encore from the date of the acquisition on March 9, 2010 through June 30, 2010. Additionally, starting in May 2010 and throughout the remainder of that year, we disposed of non-strategic Encore properties and our ownership interests in Encore Energy Partners LP (ENP).

Second Quarter Operating Highlights. We recognized net income of $259.2 million, or $0.65 per basic common share, during the second quarter of 2011 as compared to net income of $135.4 million, or $0.34 per basic common share, during the second quarter of 2010. This increase between the two periods is primarily attributable to:

A $103.1 million ($63.9 million after tax), or 21%, increase in revenue, made up of $214.4 million of additional revenue from higher realized commodity prices in the 2011 second quarter, partially offset by a decrease of $111.3 million of revenue primarily attributable to the absence in the most recent quarter of production from properties sold starting in May 2010;

A $58.6 million increase in the non-cash fair value adjustment in the mark-to-market valuation of our commodities derivatives, principally attributable to oil futures (non-cash income of $183.8 million in the second quarter of 2011 compared to $125.2 million of such non-cash income in the second quarter of 2010); and

$22.8 million of transaction and other costs related to the Encore Merger incurred in the 2010 period ($14.1 million after tax), which costs were negligible in the most recent quarter.

During the second quarter of 2011, our oil and natural gas production, which was 92% oil, averaged 64,919 BOE/d compared to 84,111 BOE/d produced during the second quarter of 2010. This drop in production is primarily attributable to the sale of non-strategic legacy Encore assets and our interests in ENP (which together had production of 20,526 BOE/d in last year s second quarter), which were sold starting in May 2010, partially offset by increases in our quarterly tertiary and Bakken production. Our tertiary oil production averaged 30,771 Bbls/d during the second quarter of 2011, up 8% over the 28,507 Bbls/d during the second quarter a year earlier. Tertiary oil production was essentially flat sequentially (down 0.2%, or 54 Bbls/d) for the second quarter. Our Bakken oil production averaged 7,626 BOE/d during the second quarter of 2011, up 69% over production of 4,500 BOE/d during the second quarter of 2010 and sequentially up 33% from levels in the first quarter of 2011. See *Results of Operations* *CO_2 Operations* and *Results of Operations* *Operating Results* *Production* for more information.

DENBURY RESOURCES INC.

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

Oil prices during the second quarter of 2011 were considerably higher than prices during the second quarter of 2010. Our average oil and natural gas price received per BOE, excluding the impact of commodity derivative contracts, was $100.06 per BOE during the second quarter of 2011, compared to $63.76 per BOE during the second quarter of 2010, a 57% increase between the two periods. Including the impact of cash settlements on our commodity derivative contracts, our average oil and natural gas price per BOE was $98.21 per BOE during the second quarter of 2011 compared to $64.13 per BOE during the second quarter of 2010, a 53% increase. During the second quarter of 2011, our oil price differentials (our received net oil price compared to NYMEX West Texas Intermediate (WTI) prices) improved significantly from a negative $4.13 per Bbl in the second quarter of 2010 to a positive $3.72 per Bbl in the second quarter of 2011, primarily due to the favorable price differential for crude oil sold under Louisiana Light Sweet (LLS) index pricing. See *Results of Operations Operating Results Oil and Natural Gas Revenues* below for more information.

August 2011 Acquisition of Remaining Working Interest in Riley Ridge. On August 1, 2011, we acquired the remaining 57.5% working interest in the Riley Ridge Federal Unit (Riley Ridge) and a working interest of approximately 33% in the 28,000 acres adjacent to Riley Ridge. As a result of the transaction, we became the operator of both projects. The purchase price was approximately $191 million, which includes a $15 million contingent payment to be paid at the time the property s gas processing facility is operational and meets specific performance conditions, plus customary closing adjustments, including payments for capital expenditures incurred between the effective date of the purchase (April 1, 2011) and closing. We currently expect the gas processing facility to be operational with the first production of natural gas and helium from Riley Ridge during the fourth quarter of 2011. The CO_2 will be re-injected into the reservoir until we have completed an additional separation facility and a CO_2 pipeline to the field, which is expected to be completed in four or five years.

Combining this acquisition with the interest in Riley Ridge that we acquired in October 2010, we estimate that our total ownership at Riley Ridge currently contains estimated proved reserves of 435 Bcf of natural gas, 15.5 Bcf of helium and 2.4 Tcf of CO_2. The adjacent 28,000 acres is estimated to contain additional probable reserves of 250 to 300 Bcf of natural gas, 9.5 to 11.5 Bcf of helium and 2.0 to 2.2 Tcf of CO_2, net to our interest. The first production of natural gas and helium from Riley Ridge is expected to begin late in the fourth quarter of 2011, with initial production of CO_2 expected in four to five years following construction of both additional facilities to separate the CO_2 from the remaining gas stream, and a CO_2 pipeline to the field.

Addition of Proved Oil and Natural Gas Reserves. We added 30.9 MMBOE of estimated proved reserves during the first six months. These reserve additions include 28.1 MMBOE of estimated proved reserves at our Bakken properties, and minor revisions to our other properties. These additions do not include estimated proved reserves of approximately 250 Bcf of natural gas (41.7 MMBOE) associated with the Riley Ridge acquisitions completed in August discussed above.

March 2011 CO_2 Purchase Contracts. In March 2011, we entered into three long-term supply contracts to purchase CO_2 from future anthropogenic sources in the Gulf Coast and Rocky Mountain regions. The three contracts are in addition to the previously disclosed long-term supply contracts Denbury currently has in place in the Gulf Coast, Rocky Mountain and Midwest regions. We will purchase 100% of the CO_2 captured from the DKRW Advanced Fuels LLC s Medicine Bow Fuel and Power LLC (MBFP) project in Medicine Bow, Wyoming, 70% of the CO_2 captured from Mississippi Power Company s Kemper County Integrated Gasification Combined Cycle (IGCC) project in Mississippi, and 100% of the CO_2 captured by Air Products LLC (Air Products) at a third-party refinery in Port Arthur, Texas. These three contracts each have an initial term of 15 to 16 years and include options to extend the term. We estimate these three sources will supply approximately 365 MMcf/d of CO_2 for our enhanced oil recovery operations, although under certain circumstances, we may be obligated to purchase up to 460 MMcf/d, a portion of which would be at a reduced price per Mcf. We expect to begin taking delivery of approximately 200 MMCF/d of CO_2 from the MBFP project in 2015, 115 MMcf/d of CO_2 from the IGCC project in 2014, and 50 MMcf/d of CO_2 from Air Products in late 2012. Our aggregate maximum purchase obligation for CO_2 purchased under these three contracts would be approximately $110 million per year (assuming purchases of 460 MMcf/d), plus transportation, assuming a $100 per barrel NYMEX oil price. The purchase price of CO_2 will fluctuate based on the changes in the price of oil.

As is the case with all of our long-term supply contracts to purchase CO_2, the three agreements entered into in March are subject to various contingencies. Construction on the IGCC and MBFP plants is in the initial stages and additional construction under the MBFP agreement is contingent upon securing debt financing and equity commitments and receipt of all necessary consents and approvals. The Air Products agreement is also contingent upon third party approvals for the necessary utilities and infrastructure.

DENBURY RESOURCES INC.

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

February 2011 Debt Refinancing. In February 2011, we issued, at par, $400 million of 6 % Senior Subordinated Notes due 2021. The net proceeds, together with cash on hand, were used to partially fund the repurchase of $525 million in principal amount of our outstanding 2013 Notes and 2015 Notes in cash tender offers to purchase $225 million principal amount of our 2013 Notes and $300 million principal amount of our 2015 Notes. In the first quarter of 2011, we accepted for purchase $169.6 million in principal of the 2013 Notes at 100.625% of par and $220.9 million in principal of the 2015 Notes at 104.125% of par. We redeemed the remaining outstanding 2015 Notes at 103.75% of par during the first quarter of 2011 and all of the remaining outstanding 2013 Notes at par on April 1, 2011. During the three and six months ended June 30, 2011, we recognized $0.3 million and $16.1 million, respectively, of loss associated with the debt repurchases, included in our income statements under the caption Loss on early extinguishment of debt .

Capital Resources and Liquidity

In June 2011, when we signed the agreement to acquire the remaining interest in Riley Ridge, which closed in August 2011, our Board of Directors approved a $50 million increase in our 2011 capital spending budget for development of the Riley Ridge plant, increasing our projected 2011 oil and gas capital investments to $1.35 billion, excluding capitalized interest, tertiary start-up costs, acquisitions and divestitures, and net of equipment leases. Our current 2011 capital budget includes the following:

- $450 million allocated for tertiary oil field expenditures;
- $350 million in the Bakken area of North Dakota;
- $250 million to be spent on our CO_2 pipelines;
- $200 million to be spent on CO_2 sources in the Jackson Dome and Riley Ridge areas; and
- $100 million on drilling, completion and other development activities in our other areas.

Based on oil and natural gas commodity futures prices in early August 2011 and our current production forecasts, excluding acquisition costs, our 2011 capital budget, including capitalized interest and tertiary start-up costs, is $150 million to $250 million greater than our anticipated cash flow from operations. These expenditures will be funded with our excess cash on hand or, if necessary, borrowings under our $1.6 billion Bank Credit Agreement under which at August 4, 2011, we had drawn $125 million, all of which was used as part of the funding of our August 1, 2011 Riley Ridge acquisition discussed above. Another potential source of funds would be proceeds if we should sell the units in Vanguard Natural Resources LLP units acquired in the sale of ENP, which have ranged in value between approximately $80 million and $100 million during the second quarter of 2011.

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 impact the timing of our future production. There are potential limitations on the amount of capital spending we can eliminate without penalties (refer to *Management s Discussion and Analysis Capital Resources and Liquidity Off-Balance Sheet Arrangements Commitments and Obligations* in our Annual Report on Form 10-K for the year ended December 31, 2010, and see *CO_2 Purchase Contracts* above and *Off-Balance Sheet Arrangements* below for further information regarding additional commitments entered into during 2011). In addition to the potential flexibility in our capital spending plans, we have approximately $1.4 billion of unused liquidity under our bank credit line and have significant oil price floors through the end of 2012 (see Note 4 to the Unaudited Condensed Consolidated Financial Statements), which together should provide us with adequate liquidity and flexibility to meet our near-term capital spending plans if oil prices were to decrease significantly.

Our capital spending estimate also assumes that we fund approximately $60 million of budgeted equipment purchases with operating leases, the amount of which is dependent upon securing acceptable financing. Through August 1, 2011, we have funded approximately $27 million of these budgeted equipment purchases with operating leases. Our net capital expenditures would increase by the amount of any shortfall in operating leases for this purchased equipment, and we anticipate funding any such additional capital expenditures under our Bank Credit Agreement.

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DENBURY RESOURCES INC.

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

In May 2011, we entered into our Fifth Amendment to the Bank Credit Agreement, reconfirming our current borrowing base of $1.6 billion, extending the maturity from March 2014 to May 2016, reducing certain margins and letter of credit fees, and adjusting the maximum permitted ratio of debt to adjusted EBITDA. See further discussion in Note 3 to the Unaudited Condensed Consolidated Financial Statements.

Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for the six month periods of 2011 and 2010:

	Six Months Ended June 30,	
In thousands	2011	2010
Oil and natural gas exploration and development:		
Drilling	$ 244,466	$ 155,503
Geological, geophysical, and acreage	14,339	15,121
Facilities	123,742	73,712
Recompletions	104,878	91,534
Capitalized interest	18,652	13,681
Total oil and natural gas exploration and development expenditures	506,077	349,551
CO_2 and other non-hydrocarbon gases capital expenditures:		
Drilling	28,768	27,113
Geological, geophysical, and acreage	10,195	4,299
Facilities	13,737	12,245
Total CO_2 and other non-hydrocarbon gases capital expenditures	52,700	43,657
Pipelines and plants capital expenditures:		
Pipelines and plants	61,292	92,500
Capitalized interest	5,499	31,481
Total pipelines and plants capital expenditures	66,791	123,981
Total capital expenditures excluding acquisitions	625,568	517,189
Oil and natural gas property acquisitions	32,482	24,243
Consideration for the Encore Merger(1)		2,952,515
Total	$ 658,050	$ 3,493,947

(1) Consideration given in the Encore Merger includes $2.09 billion for the fair value of Denbury common stock issued.

Our capital expenditures for the first six months of 2011 were funded with $523.4 million of cash flow from operations and the remainder with cash on hand at the beginning of the period. Our capital expenditures for the first six months of 2010, excluding the Encore Merger, were funded with $384.3 million of cash flow from operations along with proceeds from the sale of our interests in Genesis and the Southern Assets.

Off-Balance Sheet Arrangements. 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 our proved reserve reports. Our derivative contracts, which are recorded at fair value in our balance sheets, are discussed in Notes 4 and 5 to the Unaudited Condensed Consolidated Financial Statements.

In April 2011, we entered into three long-term drilling contracts. Our total commitment under these contracts is approximately $93 million, with $9 million expected to be paid during the remainder of 2011, $31 million in both 2012 and 2013, and $22 million in 2014.

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In May 2011, we entered into an agreement with Elk Petroleum to acquire a 65% working interest in Grieve Field, a planned CO_2 enhanced oil recovery project located in Wyoming. Denbury will invest the first $28.5 million of capital and operating costs in Phase 1. In Phase 2 of the project, Denbury may fund, at Elk s option, Elk s 35% share of the next $34.3 million of capital and operating costs, with Denbury recouping its Phase 2 expenditures (plus interest) out of Elk s 35% working interest share of production from the project. In connection with that agreement, we were assigned a CO_2 purchase and CO_2 transportation contract to purchase CO_2 reserves from Exxon Mobil Corporation s La Barge facility and transport the CO_2 to Grieve Field beginning in March of 2012. Our annual commitment under the CO_2 purchase and transportation contracts is approximately $16 million annually for 2 years and approximately $25 million annually for the remaining 8 years (assuming a $100 per barrel NYMEX oil price).

Our commitments and obligations consist of those detailed as of December 31, 2010 in our 2010 Form 10-K under *Management s Discussion and Analysis of Financial Condition and Results of Operations - Off-Balance Sheet Arrangements Commitments and Obligations*, plus the long-term drilling contracts described above, the Grieve Field obligations detailed above, and the three CO_2 purchase contracts entered into during the first quarter of 2011, which CO_2 purchase contracts are subject to numerous contingencies, as discussed under *Overview CO_2 Purchase Contracts* above.

Results of Operations

CO_2 Operations

Our focus on CO_2 operations is the primary strategy 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 Annual Report on Form 10-K for the year ended December 31, 2010 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 Annual Report on Form 10-K for the year ended December 31, 2010 for further information regarding these matters.

During the second quarter of 2011, our CO_2 production at Jackson Dome averaged 992 MMcf/d compared to an average of 768 MMcf/d produced during the second quarter of 2010 and 1,021 MMcf/d produced during the first quarter of 2011. We used 91% of this production, or 903 MMcf/d, in our tertiary operations during the second quarter of 2011, and sold the balance to our industrial customers, or to Genesis pursuant to our volumetric production payments. Refer to *Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Off-Balance Sheet Arrangements Commitments and Obligations* in our Annual Report on Form 10-K for the year ended December 31, 2010 for further discussion on our CO_2 delivery obligations. We recognized a negative proven CO_2 reserve revision during the second quarter of approximately 239 Bcf at our Jackson Dome Dri-Dock prospect. This revision was a result of the second well in this formation not being a productive well and analysis of the reprocessed seismic data, which showed incremental faulting in the Dri-Dock reservoir. Even with this downward revision, we still anticipate that we have sufficient CO_2 reserves to develop our current Gulf Coast enhanced oil recovery program and we are continuing to drill additional wells to increase our productive capability and to test the significant probable and possible reserves at Jackson Dome. At December 31, 2010, our proven CO_2 reserves at Jackson Dome were approximately 7.1 Tcf.

We spent approximately $0.27 per Mcf in operating expenses to produce our CO_2 during the first six months of 2011, comprised of $0.25 per Mcf during the first quarter of 2011 and $0.28 per Mcf during the second quarter of 2011. This rate is up significantly from our $0.22 per Mcf cost during the second quarter of 2010, due primarily to increased CO_2 royalty expense as a result of higher oil prices (to which CO_2 royalties are tied).

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The following table summarizes our tertiary oil production and tertiary lease operating expense per Bbl for each quarter in 2010 and the first and second quarters of 2011:

	Average Daily Production (Bbls/d)					
Tertiary Oil Field	First Quarter 2010	Second Quarter 2010	Third Quarter 2010	Fourth Quarter 2010	First Quarter 2011	Second Quarter 2011
Phase 1:						
Brookhaven	3,416	3,277	3,323	3,699	3,664	3,213
McComb area	2,289	2,160	2,484	2,433	2,161	1,983
Mallalieu area	3,443	3,628	3,279	3,164	2,925	2,646
Other	2,817	3,282	3,343	3,361	3,290	3,196
Phase 2:						
Heidelberg	1,708	1,857	2,806	3,422	3,374	3,548
Eucutta	3,792	3,625	3,284	3,286	3,247	3,114
Soso	3,213	3,207	3,016	2,828	2,582	2,317
Martinville	927	764	606	586	500	416
Phase 3:						
Tinsley	4,419	5,248	6,024	6,614	6,567	6,990
Phase 4:						
Cranfield	936	811	855	1,043	991	1,085
Phase 5:						
Delhi	63	648	511	703	1,524	2,263
Total tertiary oil production	27,023	28,507	29,531	31,139	30,825	30,771
Tertiary operating expense per Bbl	$ 22.67	$ 21.37	$ 22.54	$ 22.26	$ 25.40	$ 23.35

Oil production from our tertiary operations increased to an average of 30,771 Bbls/d during the second quarter of 2011, an 8% increase over our second quarter of 2010 tertiary production level of 28,507 Bbls/d, primarily due to production growth in response to continued expansion of the tertiary floods in the Tinsley, Heidelberg and Delhi Fields. Offsetting these production gains were declines in our more mature Phase 1 and Phase 2 fields (excluding Heidelberg).

The production growth rate at a tertiary flood varies from quarter to quarter as a tertiary field s production may increase rapidly when wells respond to the CO_2, plateau temporarily, and then resume its growth as additional areas of the field are developed. During a tertiary flood life cycle, facility capacity is increased from time to time, which occasionally requires temporary shutdowns during installation, thereby causing temporary declines in production. We also find it difficult to precisely predict when any given well will respond to the injected CO_2 as the CO_2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. We find all these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the entire field is developed, albeit sometimes in inconsistent patterns. These types of fluctuations were most noticeable at Tinsley and Heidelberg Fields in the first quarter of 2011, two of our fields which have exhibited strong production growth in recent periods. These fields resumed their growth during the second quarter of 2011 and these temporary fluctuations have not changed our overall outlook for these fields.

We initiated CO_2 injections at Oyster Bayou and Hastings Fields during June 2010 and December 2010, respectively. We currently anticipate tertiary production responses at Hastings Field in late 2011, assuming our CO_2 recycle facilities at this field are completed on schedule. We anticipate first production at Oyster Bayou Field late in the first quarter of 2012, also dependant on the completion of CO_2 recycle facilities.

During the second quarter of 2011, operating costs for our tertiary properties averaged $23.35 per Bbl, down 8% from our first quarter 2011 average of $25.40 per Bbl, due primarily to lower workover expenses between the respective periods, but 9% higher than our second quarter 2010 average cost of $21.37 per Bbl, due primarily to higher utility and CO_2 costs. CO_2 costs increased due to a 37% increase in injection volumes, primarily related to the ramping up of tertiary activity at our Heidelberg, Tinsley and Delhi fields, and a 27% increase in the cost of CO_2 (which is variable and partially tied to oil prices). On a per Bbl basis, our cost of CO_2 increased from $5.05 per Bbl during the second quarter of 2010 to $5.62 per Bbl during the second quarter of 2011 but remained relatively consistent with the $5.58 per Bbl level of these costs during the first quarter of 2011. Second quarter of 2011 workover expenses of $2.53 per Bbl also increased from second quarter of 2010 workover expenses of $1.62 per Bbl but decreased from first quarter of 2011 levels of $3.75 per Bbl as we completed planned mechanical integrity test repairs at Brookhaven Field and completed other workovers at Soso and Eucutta during the first quarter of 2011. For any specific field, we expect our tertiary lease operating expense per Bbl to be high initially and then decrease as production increases, ultimately leveling off until production begins to decline in the latter life of the field, when lease operating expense per barrel will again increase.

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Operating Results

Certain of our operating results and statistics for the comparative second quarters and first six months of 2011 and 2010 are included in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share and unit data	2011	2010[1]	2011	2010[1]
Operating results:				
Net income attributable to Denbury stockholders	$ 259,246	$ 135,367	$ 245,056	$ 232,255
Net income per common share basic	0.65	0.34	0.62	0.67
Net income per common share diluted	0.64	0.34	0.61	0.66
Cash flow from operations	398,521	271,123	523,353	384,291
Average daily production volumes:				
Bbls/d	59,538	65,942	59,002	55,185
Mcf/d	32,283	109,014	31,579	81,108
BOE/d	64,919	84,111	64,265	68,703
Operating revenues:				
Oil sales	$ 575,928	$ 443,984	$ 1,068,766	$ 749,188
Natural gas sales	15,171	44,044	28,525	69,726
Total oil and natural gas sales	$ 591,099	$ 488,028	$ 1,097,291	$ 818,914
Commodity derivative contracts: [2]				
Net cash receipts (payments) on settlement of commodity derivative contracts	$ (10,942)	$ 2,801	$ (9,354)	$ (57,000)
Non-cash fair value adjustment income	183,846	125,190	11,508	226,029
Total income from commodity derivative contracts	$ 172,904	$ 127,991	$ 2,154	$ 169,029
Operating expenses:				
Lease operating	$ 129,932	$ 127,743	$ 257,029	$ 223,963
Production taxes and marketing	39,688	38,100	72,439	57,417
Total production expenses	$ 169,620	$ 165,843	$ 329,468	$ 281,380
Unit prices including impact of derivative settlements: [2]				
Oil price per Bbl	$ 103.17	$ 71.68	$ 98.02	$ 67.26
Natural gas price per Mcf	7.22	6.12	7.20	6.14
Unit prices excluding impact of derivative settlements: [2]				
Oil price per Bbl	$ 106.30	$ 73.99	$ 100.08	$ 75.00
Natural gas price per Mcf	5.16	4.44	4.99	4.75
Oil and natural gas operating revenues and expenses per BOE:				
Oil and natural gas revenues	$ 100.06	$ 63.76	$ 94.33	$ 65.85

Oil and natural gas lease operating expenses	$	21.99	$	16.69	$	22.10	$	18.01
Oil and natural gas production taxes and marketing expense		6.72		4.98		6.23		4.62
Total oil and natural gas production expenses	$	28.71	$	21.67	$	28.33	$	22.63

(1) Includes the results of operations of Encore properties and ENP from March 9, 2010 through the end of the period.

(2) See Item 3, *Qualitative and Quantitative Disclosures about Market Risk,* for additional information concerning our commodity derivative contracts.

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Production. Average daily production by area for each of the four quarters of 2010 and for the first and second quarters of 2011 are shown below:

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2010[(1)]	Pro Forma First Quarter 2010[(2)]	Second Quarter 2010	Third Quarter 2010	Fourth Quarter 2010	First Quarter 2011	Second Quarter 2011
Gulf Coast Region:							
Tertiary oil fields	27,023	27,023	28,507	29,531	31,139	30,825	30,771
Non-tertiary fields:							
Mississippi	7,829	7,829	8,967	7,965	7,293	7,586	7,333
Texas	5,235	5,235	5,148	4,824	4,564	4,371	4,202
Louisiana	662	662	775	714	687	767	659
Alabama and other	997	997	1,078	1,091	1,026	1,026	1,084
Total Gulf Coast Region	41,746	41,746	44,475	44,125	44,709	44,575	44,049
Rocky Mountain Region:							
Cedar Creek Anticline	2,537	9,830	9,967	9,791	9,328	9,163	8,925
Bakken	890	3,549	4,500	4,657	5,193	5,728	7,626
Bell Creek	252	966	997	994	957	890	936
Paradox	173	675	702	738	716	635	690
Other	777	2,925	2,944	2,889	2,809	2,613	2,693
Total Rocky Mountain Region	4,629	17,945	19,110	19,069	19,003	19,029	20,870
Total Continuing Production	46,375	59,691	63,585	63,194	63,712	63,604	64,919
Disposed Properties:							
Legacy Encore properties	4,479	17,853	11,684	5,906	4,156		
ENP	2,271	9,034	8,842	8,630	8,567		
Total Production	53,125	86,578	84,111	77,730	76,435	63,604	64,919

(1) Includes production of Encore and ENP from March 9, 2010 through March 31, 2010.

(2) Represents pro forma production assuming we had reported the production from the Encore Merger beginning January 1, 2010.

Continuing production during the three months ended June 30, 2011 increased 1,334 BOE/d over the comparable 2010 production levels, and continuing production when including Encore s pre-merger production increased from 61,649 BOE/d during the first half of 2010 to 64,265 BOE/d during the first half of 2011. These increases were primarily due to production increases from the Bakken and our tertiary oil fields (see a discussion of our tertiary operations in *CO_2 Operations* above), offset by normal declines in most of our other non-tertiary properties. Additionally, our production from the Cedar Creek Anticline generally declines in periods of increasing prices due to a net profits interest associated with this production. Total production decreased 23% between the second quarters of 2010 and 2011 due to the sale of non-strategic legacy Encore properties during May 2010 through December 2010, as well as the sale of our interests in ENP in December 2010. On a year-to-date basis, total production decreased 6% between the first six months of 2010 and 2011 due primarily to the sale of the non-strategic Encore assets during 2010.

Production from our Bakken properties averaged 7,626 BOE/d in the second quarter of 2011, a 69% increase from second quarter 2010 levels and an increase of over 33% compared to first quarter 2011 production levels. The production increases in the Bakken are due to a gradual acceleration of our drilling activities in the area, as we have increased our operated drilling rigs from two, at the time of the Encore acquisition in March 2010, to five operated rigs currently. We anticipate adding a sixth rig late in the third quarter or early fourth quarter of 2011 to test our acreage in the Almond area, and a seventh rig by the end of 2011. During the first six months of 2011, we drilled and completed 16 operated wells in the Bakken. Our Bakken production for the first six months of 2011 was negatively impacted by severe winter weather and flooding which caused delays in well completions and curtailments in oil production.

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Our production during both the three and six months ended June 30, 2011 was 92% oil, as compared to 78% and 80%, during the three and six months ended June 30, 2010, respectively. This increase is due to the sales of the non-strategic Encore properties and ENP properties in 2010, which had a higher percentage of natural gas production, and increases in our tertiary and Bakken production, which are primarily oil.

Oil and Natural Gas Revenues. Although our production for the three and six months ended June 30, 2011 declined from comparable 2010 levels due to the asset sales discussed above (partially offset during the six-month period by lower production in 2010 prior to the Encore Merger which closed in March 2010), our oil and natural gas revenues increased significantly in the current periods due to higher oil prices. These changes in oil and natural gas revenues, excluding any impact of our commodity derivative contracts, are reflected in the following table:

	Three Months Ended June 30, 2011 vs. 2010		Six Months Ended June 30, 2011 vs. 2010	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase in commodity prices	$ 214,398	44%	$ 331,259	40%
Decrease in production	(111,327)	(23%)	(52,882)	(6%)
Total increase in oil and natural gas revenues	$ 103,071	21%	$ 278,377	34%

Excluding any impact of our commodity 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 2011 and 2010:

	Three Months Ended March 31,		Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010	2011	2010
Net Realized Prices:						
Oil price per Bbl	$ 93.67	$ 76.53	$ 106.30	$ 73.99	$ 100.08	$ 75.00
Natural gas price per Mcf	4.81	5.40	5.16	4.44	4.99	4.75
Price per BOE	88.42	69.21	100.06	63.76	94.33	65.85
NYMEX Differentials:						
Oil per Bbl	$ (0.59)	$ (2.08)	$ 3.72	$ (4.13)	$ 1.64	$ (3.36)
Natural gas per Mcf	0.61	0.37	0.78	0.09	0.70	0.06

During the second quarter of 2011, our oil price differentials improved significantly, primarily due to the favorable price differential for crude oil sold under LLS index pricing. Company-wide oil price differentials in the second quarter of 2011 were $3.72 per Bbl above NYMEX, as compared to an average negative differential of $4.13 per Bbl below NYMEX in the second quarter of 2010 and an average negative differential of $0.59 per Bbl during the first quarter of 2011. Our oil price differential in the second quarter of 2010 reflected production from the non-strategic Encore properties sold in 2010, which typically received lower oil prices than our legacy production. During the latter part of the first quarter, the LLS index price increased significantly more than NYMEX prices, causing the LLS differential to increase significantly, and it remained high throughout the second quarter. For the second quarter of

2011, this LLS differential averaged a positive $15.32 per barrel on a trade-month basis, as compared to a $9.28 positive differential in the first quarter of 2011 and a more typical $3.21 positive differential in

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the second quarter of 2010. It is uncertain how long this LLS differential will remain at this level, Because our derivative contracts are based on NYMEX prices, they do not impact the differential we receive. We currently sell approximately (a) 40% of our crude oil based on the LLS index price, although due to contract provisions we may not realize the full differential; (b) approximately 40% based on WTI prices; and (c) approximately 20% based on various other indexes, most of which also improved relative to WTI, but to a lesser degree.

Commodity Derivative Contracts. The following tables summarize the impact our commodity derivative contracts had on our operating results for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30,					
	2011	2010	2011	2010	2011	2010
	Oil		Natural Gas		Total Commodity Derivative	
In thousands	Derivative Contracts		Derivative Contracts		Contracts	
Non-cash fair value gain (loss)	$ 187,194	$ 145,099	$ (3,348)	$ (19,909)	$ 183,846	$ 125,190
Cash settlement receipts (payments)	(16,972)	(13,829)	6,030	16,630	(10,942)	2,801
Total	$ 170,222	$ 131,270	$ 2,682	$ (3,279)	$ 172,904	$ 127,991

	Six Months Ended June 30,					
	2011	2010	2011	2010	2011	2010
	Oil		Natural Gas		Total Commodity Derivative	
In thousands	Derivative Contracts		Derivative Contracts		Contracts	
Non-cash fair value gain (loss)	$ 20,130	206,920	(8,622)	19,109	$ 11,508	$ 226,029
Cash settlement receipts (payments)	(22,000)	(77,379)	12,646	20,379	(9,354)	(57,000)
Total	$ (1,870)	$ 129,541	$ 4,024	$ 39,488	$ 2,154	$ 169,029

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our commodity derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the changes in fair value of these contracts, as outlined above, are recognized currently in the income statement. See Notes 4 and 5 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

Production Expenses. Our lease operating expenses increased 2% during the three months ended June 30, 2011 compared to the same period in 2010 primarily as a result of the increased CO_2 injections as we continued to ramp up tertiary activities at Tinsley, Heidelberg and Delhi fields during 2010 and 2011, the cost of CO_2 (which are variable and partially tied to oil prices) and workover expenses on our tertiary operations (see discussion of those expenses under *CO_2 Operations*), offset by the sale of the non-strategic legacy Encore and ENP properties during 2010.

The 15% increase in lease operating expense during the six months ended June 30, 2011 compared to 2010 was further impacted by the inclusion in the 2011 period of a full six months of lease operating expense related to properties acquired in the Encore Merger on March 9, 2010.

Lease operating expense per BOE averaged $21.99 per BOE and $22.10 per BOE for the three and six months ended June 30, 2011, compared to $16.69 per BOE and $18.01 per BOE for the same periods in 2010. These increases from the respective prior periods are attributable to the sale of the non-strategic Encore and ENP properties from May 2010 through December 2010, which generally had a lower operating cost per BOE than Denbury s legacy properties. However, second quarter 2011 lease operating expenses per BOE decreased from $22.20 per BOE in the first quarter of 2011. Our tertiary operating costs, which have historically been higher than our company-wide operating costs, averaged $23.35 per BOE and $24.37 per BOE during the three and six months ended June 30, 2011, compared to $21.37 per BOE and $22.00 per BOE for the same periods in 2010. See *CO_2 Operations* for a more detailed discussion.

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Generally, production taxes change in relation to oil and natural gas revenues, and marketing expenses change in relation to production volumes. The 21% increase in oil and natural gas revenues between the second quarters of 2010 and 2011 contributed to severance taxes increasing from $28.7 to $33.4 million, respectively. Likewise, the 34% increase in oil and natural gas revenues between the first six months of 2010 and 2011 contributed to severance taxes increasing from $43.6 million to $60.9 million, respectively. These severance tax increases in both comparative periods were partially offset by lower marketing expenses primarily attributable to lower production volumes in 2011.

General and Administrative Expenses (G&A)

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per BOE data and employees	2011	2010	2011	2010
Gross cash G&A expense	$ 60,137	$ 57,909	$ 127,834	$ 106,183
Gross stock-based compensation	9,687	7,363	21,024	17,302
State franchise taxes	1,668	965	2,827	2,035
Operator labor and overhead recovery charges	(31,423)	(29,086)	(61,139)	(51,131)
Capitalized exploration and development costs	(9,169)	(5,959)	(15,800)	(10,488)
Net G&A expense	$ 30,900	$ 31,192	$ 74,746	$ 63,901
G&A per BOE:				
Net cash G&A expense	$ 3.73	$ 3.15	$ 4.78	$ 3.81
Net stock-based compensation	1.22	0.79	1.41	1.17
State franchise taxes	0.28	0.13	0.24	0.16
Net G&A expense	$ 5.23	$ 4.07	$ 6.43	$ 5.14
Employees as of June 30	1,283	1,304	1,283	1,304

Gross cash G&A expenses increased $2.2 million (4%) and $21.7 million (20%) during the three and six months ended June 30, 2011, respectively, as compared to the same periods of 2010. The increase between the comparative second quarters is reflective of higher salary costs which we consider necessary in order to remain competitive in our industry. The year-to-date comparative increase is primarily impacted by increased expense resulting from the Encore Merger as the 2010 period includes the effect of the Encore Merger beginning on the acquisition date, March 9, 2010. The number of employees at June 30, 2011, compared to June 30, 2010, decreased slightly, by 2%, primarily due to the departure of Encore transition employees who did not accept permanent positions with Denbury and who completed their transition period. However, prior to the Encore Merger, our headcount was 856 employees.

Additional expense attributable to the legacy Encore office leases and the new Denbury headquarters lease, together with related moving costs, contributed to the higher cash G&A expense during the first six months of 2011. Additionally, stock-based compensation expense increased $2.3 million for the second quarter 2011 when compared to levels in the same period of 2010, due primarily to higher compensation levels.

Gross cash G&A expenses decreased $7.6 million, or 11% from levels in the first quarter of 2011, due primarily to lower compensation and employee-related costs and lower professional fees in the current quarter. The first quarter of 2011 included higher payroll tax burdens and 401(k) matching contribution associated with bonus payouts, the true-up of long-term incentive compensation estimates, incremental costs associated with relocating our headquarters and higher professional fees associated with year-end work.

The increase in gross G&A expense during the three and six months ended June 30, 2011, as compared to those costs in the same periods of 2010, was offset in part by an increase in operator overhead recovery charges. 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 labor and overhead charges increased by 8% and 20% during the three and six months ended June 30, 2011, as compared to the same periods in 2010. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

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The net effect of these changes resulted in a 1% decrease (a 29% increase on a per BOE basis) in G&A expense between the comparable second quarters of 2011 and 2010. Lower production in the most recent quarter attributable to the 2010 sale of properties was the primary factor relating to the higher cost per BOE, as any cost savings as a result of the property sales were offset by other expenses, including compensation increases effective at the beginning of 2011 and incremental expense attributable to the legacy Encore office leases and the new Denbury headquarters noted above.

Interest and Financing Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per BOE data and interest rates	2011	2010	2011	2010
Cash interest	$ 50,509	$ 60,966	$ 104,715	$ 105,940
Non-cash interest	4,934	6,367	10,462	9,121
Less: capitalized interest	(13,194)	(23,850)	(24,151)	(45,162)
Interest expense, net	$ 42,249	$ 43,483	$ 91,026	$ 69,899
Interest income and other	$ 4,955	$ 4,520	$ 8,004	$ 6,390
Net cash interest expense and other income per BOE (1)	$ 5.54	$ 4.43	$ 6.31	$ 4.53
Average debt outstanding	$ 2,305,104	$ 3,152,564	$ 2,409,284	$ 2,689,894
Average interest rate (2)	8.8%	7.7%	8.7%	7.9%

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

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

Cash interest expense decreased $10.5 million during the three month period ending June 30, 2011, as compared to the same period in 2010, primarily due to a decrease in our average debt outstanding. Our debt level increased in early 2010 as a result of the Encore Merger and decreased throughout 2010 and in early 2011 as we repaid debt with proceeds from the sale of non-strategic legacy Encore assets and our ENP ownership interest. Year-to-date cash interest expense remained relatively consistent with that incurred in the same period in 2010. The decrease in cash interest expense during both the three and six month comparative periods was offset by lower capitalized interest relating primarily to the Green Pipeline, which was completed and placed into service at the end of June 2010.

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DENBURY RESOURCES INC.

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

Depletion, Depreciation, and Amortization

In thousands, except per BOE data	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Depletion, depreciation, and amortization (DD&A) of oil and natural gas properties	$ 91,961	$ 116,034	$ 174,047	$ 187,231
Depletion and depreciation of CO_2 assets	4,588	5,680	9,178	10,980
Asset retirement obligations	1,696	1,692	3,259	2,799
Depreciation of other fixed assets	5,250	5,803	10,605	10,071
Total DD&A	$ 103,495	$ 129,209	$ 197,089	$ 211,081
DD&A per BOE:				
Oil and natural gas properties	$ 15.85	$ 15.38	$ 15.24	$ 15.28
CO_2 assets and other fixed assets	1.67	1.50	1.70	1.69
Total DD&A cost per BOE	$ 17.52	$ 16.88	$ 16.94	$ 16.97

Depletion of oil and natural gas properties decreased on an absolute dollars basis during the three and six months ended June 30, 2011 as compared to the same periods of 2010, primarily due to the sale of non-strategic legacy Encore assets and our ownership interests in ENP during 2010. Depletion of oil and gas properties increased on a per BOE basis during the second quarter of 2011 compared to 2010, primarily due to higher finding and development costs per barrel associated with the incremental Bakken capital program and upward revisions in estimated future development costs.

We continually evaluate the performance of our 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.

Our DD&A expense for our CO_2 assets decreased on an absolute basis for the three and six months ended June 30, 2011 compared to the same periods in 2010 due to proved CO_2 reserve increases at Jackson Dome and Riley Ridge at the end of 2010. On a per BOE basis, DD&A expense for our CO_2 assets and other fixed assets increased for the three months ended June 30, 2011 compared to those in the prior-year quarter due to decreased oil and natural gas production volumes as a result of the sale of non-strategic Encore properties and our interests in ENP during 2010.

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 June 30, 2011. However, if oil and natural gas prices were to decrease significantly in subsequent periods, we may be required to record 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, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, and additional capital spent.

Encore Transaction and Other Costs

FASC *Business Combinations* topic requires that all transaction-related costs (advisory, legal, accounting, due diligence, integration, etc.) be expensed as incurred. We recognized transaction and other costs of $2.0 million and $4.4 million for the three and six months ended June 30, 2011, respectively, associated with the Encore Merger, including $1.8 million and $3.6 million, respectively, related to severance costs. Transaction and other costs of $22.8 million and $67.8 million for the three and six months ended June 30, 2010, respectively, included

$19.5 million and $20.7 million, respectively, of severance costs, and were significantly higher than 2011 levels. We anticipate that these severance costs will decline in the remainder of 2011 as the integration winds down and fewer former Encore transition employees remain.

DENBURY RESOURCES INC.

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

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per BOE amounts and tax rates	2011	2010	2011	2010
Current income tax provision	$ 12,028	$ 6,941	$ 11,180	$ 7,610
Deferred income tax provision	152,528	74,422	144,620	150,694
Total income tax provision	$ 164,556	$ 81,363	$ 155,800	$ 158,304
Average income tax provision per BOE	$ 27.85	$ 10.63	$ 13.39	$ 12.73
Effective tax rate	38.8%	35.1%	38.9%	38.7%

Our income taxes are based on an estimated statutory rate of approximately 38%. Our effective tax rate for the second quarter of 2011 was slightly higher compared to our statutory rate, primarily due to nondeductible expenses. Our effective tax rate for the second quarter of 2010 was lower due to the remeasurement of our deferred tax liabilities as a result of the May 2010 sale of certain legacy Encore properties in the Permian Basin, Mid-continent area and East Texas Basin (the Southern Assets), which resulted in an income tax benefit of approximately $3 million recorded in the second quarter of 2010. The nondeductible expenses in 2011 and the income tax benefit recorded in 2010 resulted in a slight increase in the effective tax rate, to 38.9%, during the six months ended June 30, 2011, as compared to 38.7% in the six months ended June 30, 2010. The current income tax expense represents our state income taxes during the three and six months ended June 30, 2011 and 2010.

As of June 30, 2011, we had an estimated $39.8 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.5 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2011 or future years. The enhanced oil recovery credits do not begin to expire until 2024. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

In the third quarter of 2008, we obtained approval from the National Office of the Internal Revenue Service (IRS) to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. As a result of the approved change in method of tax accounting, beginning with the 2007 tax year we began to deduct, rather than capitalize, such costs for tax purposes, and applied for tax refunds associated with such change for our 2004 and 2006 tax years. Notwithstanding its consent to our change in tax accounting in 2008, the IRS subsequently exercised its prerogative to challenge the tax accounting method we used. In late January 2011, we received a Technical Advice Memorandum (TAM) issued by the IRS National Office disapproving our method of accounting and revoking its consent to our change, on a prospective basis only, commencing January 1, 2011. Henceforth, beginning with the 2011 tax year, we are returning to capitalizing and depreciating the costs of these assets for tax purposes. As a result of the prospective nature of the IRS s determination, there should be no change in our position with respect to the deductibility of these costs for 2007, 2008, 2009 and 2010. However, refund claims of $10.6 million for tax years through 2006 are pending and are pending review by the Joint Committee on Taxation of the U.S. Congress. We are unable to assess the outcome of any such review, nor how that outcome may affect the other years covered by the TAM.

The President s 2012 budget, as well as certain Congressional legislative initiatives, have proposed repealing many tax incentives for the oil and gas industry. Those items that would have the most significant impact on us would include the loss of the domestic manufacturing deduction, the repeal of the immediate expensing of intangible drilling costs and tertiary injectant costs, and the elimination of the percentage depletion allowance. It is uncertain whether these or similar tax law changes will be enacted, and if so what the effective date of any such changes might be, although the current proposals would not take effect until 2012. If some or all of these proposals were enacted and included us, they would likely increase the amount of cash taxes that we pay in future periods, and, accordingly, could impact our forecasted capital expenditure budget.

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	2011	2010	2011	2010
Oil and natural gas revenues	$ 100.06	$ 63.76	$ 94.33	$ 65.85
Gain (loss) on settlements of derivative contracts	(1.85)	0.37	(0.80)	(4.58)
Lease operating expenses	(21.99)	(16.69)	(22.10)	(18.01)
Production taxes and marketing expenses	(6.72)	(4.98)	(6.23)	(4.62)
Production netback	69.50	42.46	65.20	38.64
Non-tertiary CO_2 operating margin	0.59	0.39	0.53	0.49
General and administrative expenses	(5.23)	(4.07)	(6.43)	(5.14)
Transactions and other costs related to the Encore Merger	(0.34)	(2.98)	(0.38)	(5.45)
Net cash interest expense and other income	(5.54)	(4.43)	(6.31)	(4.53)
Current income taxes and other	(0.74)	0.10	0.28	0.66
Changes in assets and liabilities relating to operations	9.22	3.95	(7.90)	6.23
Cash flow from operations	67.46	35.42	44.99	30.90
DD&A	(17.52)	(16.88)	(16.94)	(16.97)
Deferred income taxes	(25.82)	(9.72)	(12.43)	(12.12)
Gain on sale of interests in Genesis				8.17
Loss on early extinguishment of debt	(0.06)		(1.39)	
Non-cash fair value derivative adjustments	31.12	16.45	0.99	18.25
Net income attributable to noncontrolling interest		1.95		1.47
Changes in assets and liabilities and other non-cash items	(11.30)	(9.53)	5.85	(11.02)
Net income attributable to Denbury stockholders	$ 43.88	$ 17.69	$ 21.07	$ 18.68

Critical Accounting Policies

For additional discussion of our critical accounting policies, which remain unchanged, 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, 2010.

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, dates of pipeline construction commencement and completion, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, timing of CO_2 injections in tertiary flooding projects, cost savings, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves, potential reserves from tertiary operations, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and natural gas prices, liquidity, cash flows, availability of capital, borrowing capacity, 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 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, or other words that 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 our 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 us or on our behalf. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for our oil and natural gas; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets; changes in interest rates; general economic conditions; competition and government regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and natural gas drilling and production activities or which are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

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DENBURY RESOURCES INC.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Long-Term Debt and Interest Rate Sensitivity

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. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies. 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, 2011:

In thousands, except percentages	2014	2015	2016	2017	2020	2021	Carrying Value	Fair Value
Variable rate debt:								
Bank Credit Agreement	$	$	$	$	$	$	$	$
Fixed rate debt:								
9.5% Senior Subordinated Notes due 2016			224,920				238,142	249,942
9.75% Senior Subordinated Notes due 2016			426,350				406,354	476,446
8.25% Senior Subordinated Notes due 2020					996,273		996,273	1,085,938
6.375% Senior Subordinated Notes due 2021						400,000	400,000	400,000
Other Subordinated Notes	1,072	485		2,250			3,843	3,807

Commodity Derivative Contracts and Commodity Price Sensitivity

From time to time, we enter into 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. We currently employ a strategy to hedge a portion of our forecasted production for a period generally ranging from approximately 12 to 18 months in advance (although we will hedge farther in advance if deemed prudent), as we believe it is important to protect our future cash flow for a short period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times. See Note 4, *Derivative Instruments and Hedging Activities,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. 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 commodity derivative contracts are with parties that are lenders under our bank credit agreement. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our commodity 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.

At June 30, 2011, our commodity derivative contracts were recorded at their fair value, which was a net liability of approximately $32.5 million (excluding $15.6 million of deferred premiums that Denbury is obligated to pay for its derivative contracts, which payments are not subject to changes in commodity prices), which is less than the $44.0 million fair value liability recorded at December 31, 2010. This change is primarily related to changes in oil futures prices between December 31, 2010 and June 30, 2011.

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DENBURY RESOURCES INC.

Based on NYMEX crude oil and natural gas futures prices as of June 30, 2011, 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:

In thousands	Crude Oil Derivative Contracts (Payment)	Natural Gas Derivative Contracts Receipt
Based on:		
NYMEX futures prices as of June 30, 2011	$ (9,390)	$ 24,508
10% increase in prices	(81,222)	18,312
10% decrease in prices	(2,952)	30,703

Equity Price Sensitivity

Our investment in Vanguard common units is considered an investment in available-for-sale securities, which is recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. This investment is thus subject to equity price sensitivity, as fair value is determined by quoted market prices. We estimate that a hypothetical 10% increase or decrease in quoted market prices for Vanguard common units would result in a $8.8 million unrealized gain or loss, respectively, as of June 30, 2011.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company s management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, the Company s Chief Executive Officer and our Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of June 30, 2011, to ensure: that information required to be disclosed in the reports it files and submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company s management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the second quarter of fiscal 2011, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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DENBURY RESOURCES INC.
PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information with respect to this item is incorporated by reference from our Annual Report on Form 10-K for the year ended December 31, 2010.

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference from Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010. There have been no material changes to the risk factors since the filing of such Form 10-K.

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

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the second quarter of 2011, consisting entirely of delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
April 2011	17,272	$ 23.97		$
May 2011	9,466	21.28		
June 2011	14,479	19.95		
Total	41,217	21.94		$

Item 6. Exhibits

Exhibit	Description
3.1	Amended and Restated Bylaws of Denbury Resources Inc. effective as of June 17, 2011 (incorporated by reference as Exhibit 3.1 of our Form 8-K filed on June 21, 2011).
4.1	Fifth Amendment to Credit Agreement dated as of March 9, 2010, dated as of May 19, 2011, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference as Exhibit 99.1 of our Form 8-K filed on May 20, 2011).
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101*	Interactive Data Files.

* Filed herewith.

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DENBURY RESOURCES INC.
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.

By: /s/ Mark C. Allen
Mark C. Allen
Senior Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary

By: /s/ Alan Rhoades
Alan Rhoades
Vice President and Chief Accounting Officer

Date: August 8, 2011