DENBURY RESOURCES INC
Form 10-Q
May 10, 2012

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 March 31, 2012

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 (State or other jurisdiction of incorporation or organization)	20-0467835 (I.R.S. Employer Identification No.)
5320 Legacy Drive, Plano, TX (Address of principal executive offices)	75024 (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 April 30, 2012
Common Stock, $.001 par value	390,635,689

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Denbury Resources Inc.
Unaudited Condensed Consolidated Balance Sheets
(In thousands, except par value and share data)

	March 31, 2012	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 77,366	$ 18,693
Restricted cash	140,131	—
Accrued production receivable	303,552	294,689
Trade and other receivables, net	150,379	164,446
Short-term investments	—	86,682
Derivative assets	23,015	47,402
Deferred tax assets	47,641	50,156
Other current assets	15,951	22,045
Total current assets	758,035	684,113
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	7,329,967	7,026,579
Unevaluated	995,352	1,157,106
CO_2 properties	613,308	596,003
Pipelines and plants	1,755,679	1,701,756
Other property and equipment	162,363	157,674
Less accumulated depletion, depreciation, amortization, and impairment	(2,751,999)	(2,627,493)
Net property and equipment	8,104,670	8,011,625
Derivative assets	1,245	29
Goodwill	1,236,318	1,236,318
Other assets	241,794	252,339
Total assets	$ 10,342,062	$ 10,184,424
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 359,141	$ 429,336
Oil and gas production payable	196,622	197,092
Derivative liabilities	41,972	26,523
Current maturities of long-term debt	8,853	8,316
Total current liabilities	606,588	661,267
Long-term liabilities		
Long-term debt, net of current portion	2,727,700	2,669,729
Asset retirement obligations	81,935	88,726

Derivative liabilities		22,013		18,872
Deferred taxes		1,953,253		1,918,576
Other liabilities		22,131		20,756
Total long-term liabilities		4,807,032		4,716,659
Commitments and contingencies (Note 6)				
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; 404,722,399 and 402,946,070 shares issued, respectively		405		403
Paid-in capital in excess of par		3,102,617		3,090,374
Retained earnings		2,022,942		1,909,475
Accumulated other comprehensive loss		(400)		(418)
Treasury stock, at cost, 14,146,005 and 13,965,673 shares, respectively		(197,122)		(193,336)
Total stockholders' equity		4,928,442		4,806,498
Total liabilities and stockholders' equity	$	10,342,062	$	10,184,424

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 March 31, 2012			2011		
Revenues and other income						
Oil, natural gas, and related product sales	$	633,501		$	506,192	
CO2 sales and transportation fees		6,795			4,924	
Interest income and other income		4,820			3,049	
Total revenues and other income		645,116			514,165	
Expenses						
Lease operating expenses		137,964			123,797	
Marketing expenses		10,830			5,303	
CO2 discovery and operating expenses		6,205			1,946	
Taxes other than income		43,694			32,483	
General and administrative		36,607			42,319	
Interest, net of amounts capitalized of $19,445 and $10,957, respectively		36,314			48,777	
Depletion, depreciation, and amortization		120,895			93,594	
Derivatives expense		45,275			170,750	
Loss on early extinguishment of debt		—			15,783	
Impairment of assets		17,300			—	
Other expenses		10,720			2,359	
Total expenses		465,804			537,111	
Income (loss) before income taxes		179,312			(22,946	)
Income tax provision (benefit)						
Current income taxes		28,708			(848	)
Deferred income taxes		37,137			(7,908	)
Net income (loss)	$	113,467		$	(14,190	)
Net income (loss) per common share – basic	$	0.29		$	(0.04	)
Net income (loss) per common share – diluted	$	0.29		$	(0.04	)
Weighted average common shares outstanding						
Basic		386,367			397,386	
Diluted		390,943			397,386	

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 March 31, 2012	2011
Net income (loss)	$ 113,467	$ (14,190)
Other comprehensive income, net of income tax:		
Net unrealized gain on available-for-sale securities, net of tax of $2,550	—	4,163
Interest rate lock derivative contracts reclassified to income, net of tax of $11 and $11, respectively	18	17
Total other comprehensive income	18	4,180
Comprehensive income (loss)	$ 113,485	$ (10,010)

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)

	Three Months Ended March 31, 2012	2011
Cash flows from operating activities		
Net income (loss)	$ 113,467	$ (14,190)
Adjustments needed to reconcile to net cash flow provided by operations:		
Depletion, depreciation, and amortization	120,895	93,594
Deferred income taxes	37,137	(7,908)
Stock-based compensation	7,913	10,201
Noncash fair value derivative adjustments	44,113	172,367
Loss on early extinguishment of debt	—	15,783
Amortization of debt issuance costs and discounts	3,674	5,051
Impairment of assets	17,300	—
Other, net	7,725	(3,681)
Changes in operating assets and liabilities:		
Accrued production receivable	(8,863)	(44,243)
Trade and other receivables	9,162	(17,484)
Other current and long-term assets	676	(8,449)
Accounts payable and accrued liabilities	(32,861)	(90,382)
Oil and natural gas production payable	(470)	18,770
Other liabilities	(28,214)	(4,597)
Net cash provided by operating activities	291,654	124,832
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(302,246)	(190,296)
Acquisitions of oil and natural gas properties	(592)	(29,801)
CO2 capital expenditures	(30,693)	(27,150)
Pipelines and plants capital expenditures	(60,441)	(38,897)
Purchases of other assets	(4,945)	(12,770)
Net proceeds from sales of oil and natural gas properties and equipment	166,703	11,989
Addition to restricted cash	(140,131)	—
Proceeds from sale of short-term investments	83,545	—
Other	(83)	1,882
Net cash used for investing activities	(288,883)	(285,043)
Cash flows from financing activities:		
Bank repayments	(150,000)	(130,000)
Bank borrowings	210,000	130,000
Repayment of senior subordinated notes	—	(469,552)
Premium paid on repayment of senior subordinated notes	—	(13,137)
Net proceeds from issuance of senior subordinated notes	—	400,000
Net proceeds from issuance of common stock	3,949	5,253
Costs of debt financing	(11)	(8,441)
Other	(8,036)	(7,924)
Net cash provided by (used for) financing activities	55,902	(93,801)

Net increase (decrease) in cash and cash equivalents		58,673		(254,012)
Cash and cash equivalents at beginning of period		18,693		381,869
Cash and cash equivalents at end of period	$	77,366	$	127,857

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO2 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 our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis on our CO2 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, 2011. Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company," or "Denbur 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 March 31, 2012, our consolidated results of operations for the three months ended March 31, 2012 and 2011, and our consolidated cash flows for the three months ended March 31, 2012 and 2011. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter. On the Unaudited Condensed Consolidated Statements of Operations for the three months ended March 31, 2011, "Taxes other than income" is a new line item and includes oil and natural gas ad valorem taxes, which were reclassified from "Lease operating expenses," franchise taxes and property taxes on buildings, which were reclassified from "General and administrative," oil and natural gas production taxes, which were reclassified from "Production taxes and marketing expenses" used in prior reports and CO2 property ad valorem and production taxes, which were classified from "CO2 discovery and operating expenses." Such reclassifications had no impact on our reported total expenses or net income.

Restricted Cash

Restricted cash consists of proceeds from the sale of oil and gas properties in February 2012 that are held by a qualified intermediary and are restricted for the pending acquisition of Thompson Field (see Note 8, Subsequent Events) to facilitate an anticipated like-kind exchange transaction.

Net Income Per Common Share

Basic net income per common share is computed by dividing net income attributable to common 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 to net income and common shares of the potential dilution from stock options, stock appreciation rights (“SARs”), nonvested restricted stock, and nonvested performance equity awards. For the three months ended March 31, 2012 and 2011, there were no adjustments to net income for purposes of calculating diluted net income per common share.

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Notes to Unaudited Condensed Consolidated Financial Statements

The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share calculations for the periods indicated:

In thousands	Three Months Ended March 31, 2012	2011
Basic weighted average common shares	386,367	397,386
Potentially dilutive securities:		
Stock options and SARs	3,330	—
Performance equity awards	117	—
Restricted stock	1,129	—
Diluted weighted average common shares	390,943	397,386

Basic weighted average common shares excludes 3.9 million and 3.7 million shares of nonvested restricted stock during the three months ended March 31, 2012 and 2011, respectively. 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, the nonvested 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 antidilutive:

In thousands	Three Months Ended March 31, 2012	2011
Stock options and SARs	3,179	12,641
Restricted stock	10	3,453
Total	3,189	16,094

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 December 31, 2011, 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 Encore Energy Partners LP to a subsidiary of Vanguard on December 31, 2010. We received distributions of $1.8 million on the Vanguard common units we owned for the three months ended March 31, 2011, which are included in “Interest income and other income” on our Unaudited Condensed Consolidated Statements of Operations. During January 2012, the Company sold its investment in Vanguard for cash consideration of $83.5 million, net of related transaction fees. The Company recognized a pretax loss on the sale of $3.1 million, which is included in “Other expenses” on our Unaudited Condensed Consolidated Statements of Operations for the three months ended March 31, 2012.

Recently Adopted Accounting Pronouncements

Comprehensive Income. In June 2011, the Financial Accounting Standards Board ("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 was effective for Denbury beginning January 1, 2012. Since ASU 2011-05 only amended presentation requirements, it did not have a material effect on our consolidated financial statements.

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Fair Value. In May 2011, the FASB issued 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 Financial Accounting Standards Board Codification ("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 was effective for Denbury beginning January 1, 2012. The adoption of ASU 2011-04 did not have a material effect on our consolidated financial statements, but did require additional disclosures. See Note 5, Fair Value Measurements.

Note 2. Acquisitions and Divestitures

Acquisitions

August 2011 Acquisition of Reserves in Rocky Mountain Region at Riley Ridge

In August 2011, we acquired the remaining 57.5% working interest in the Riley Ridge Federal Unit ("Riley Ridge"), located in the LaBarge Field of southwestern Wyoming. Riley Ridge contains natural gas resources, as well as helium and CO_2 resources. The purchase included a 57.5% interest in a gas plant which will separate the helium and natural gas from the commingled gas stream, and interests in certain surrounding properties. The purchase price was approximately $214.8 million after closing adjustments, including a $15.0 million deferred payment to be made at the time the Riley Ridge gas plant is operational and meets specific performance conditions. The gas plant is currently undergoing readiness testing, and we expect it to become operational during the fourth quarter of 2012.

The August 2011 acquisition of Riley Ridge meets the definition of a business under the FASC Business Combinations topic. The fair values assigned to assets acquired and liabilities assumed in the August 2011 acquisition have been finalized and no adjustments have been made to amounts previously disclosed in our Form 10-K for the period ended December 31, 2011. Because the Riley Ridge plant is not yet operational, current production at the field is negligible. As a result, pro forma information has not been disclosed due to the immateriality of revenues and expenses during 2011.

Divestitures

On January 10, 2012, we entered into an agreement to sell certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155.0 million. We entered into the sales agreement with a privately held entity in which a member of our Board of Directors serves as chairman of the board, in a sale for which there was a competing bid contained in a multi-property purchase proposal. On February 29, 2012, we closed on the sale with net proceeds of $144.8 million, after preliminary closing adjustments. The sale had an effective date of December 1, 2011 and consequently, operating net revenues after the effective date, net of capital expenditures, along with any other purchase price adjustments, were adjustments to the selling price. We did not record a gain or loss on the sale of the properties in accordance with the full cost method of accounting.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 3. Long-Term Debt

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

In thousands	March 31, 2012	December 31, 2011
Bank Credit Facility	$ 445,000	$ 385,000
9½% Senior Subordinated Notes due 2016, including premium of $11,170 and $11,854, respectively	236,090	236,774
9¾% Senior Subordinated Notes due 2016, including discount of $16,783 and $17,854, respectively	409,567	408,496
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 % Senior Subordinated Notes due 2021	400,000	400,000
Other Subordinated Notes, including premium of $31 and $33, respectively	3,838	3,840
NEJD Pipeline financing	162,704	163,677
Free State Pipeline financing	79,189	79,597
Capital lease obligations	3,892	4,388
Total	2,736,553	2,678,045
Less current obligations	(8,853)	(8,316)
Long-term debt and capital lease obligations	$ 2,727,700	$ 2,669,729

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. Certain of DRI's subsidiaries guarantee our debt, and each such subsidiary guarantor is 100% owned by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the guarantees are full and unconditional and joint and several obligations of the subsidiary guarantors.

Bank Credit Facility

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 party thereto (as amended 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 of each year and upon requested special redeterminations. The borrowing base is adjusted at the banks' discretion and is based in part upon certain external factors over which we have no control. The weighted average interest rate on borrowings under the credit facility, evidenced by the Bank Credit Agreement (the "Bank Credit Facility") was 2.0% for the three months ended March 31, 2012. We incur a commitment fee on the unused portion of the Bank Credit Facility of either 0.375% or 0.5%, based on the ratio of outstanding borrowings under the Bank Credit Facility to the borrowing base. The Bank Credit Agreement is scheduled to mature in May 2016.

In April 2012, we entered into the Seventh Amendment to the Bank Credit Agreement (the "Bank Amendment"). Under the Bank Amendment, we increased the amount of additional permitted subordinate debt (other than refinancing debt) from $300.0 million to $650.0 million. At the same time, the banks reaffirmed Denbury's borrowing base of $1.6 billion under the Bank Credit Facility until the next redetermination, which is scheduled to occur on or around November 1, 2012.

6 % Senior Subordinated Notes due 2021

In February 2011, we issued $400.0 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 $393.0 million were used to repurchase a portion of our outstanding 2013 Notes and 2015 Notes (see Redemption of our 2013 and 2015 Notes below).

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Notes to Unaudited Condensed Consolidated Financial Statements

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 7½% Senior Subordinated Notes due 2013 (“2013 Notes”) and all $300.0 million principal amount of our 7½% Senior Subordinated Notes due 2015 (“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 Notes 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 $15.8 million loss during the three months ended March 31, 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

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; 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” in our Unaudited Condensed Consolidated Statements of Operations.

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

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

	Three Months Ended March 31,	
In thousands	2012	2011
Oil		
Payment on settlements of derivative contracts	$ 8,230	$ 5,028
Fair value adjustments to derivative contracts – expense	42,445	167,064
Total derivatives expense – oil	50,675	172,092
Natural Gas		
Receipt on settlements of derivative contracts	(7,040)	(6,616)
Fair value adjustments to derivative contracts – expense	1,640	5,274

Total derivatives income – natural gas		(5,400	)		(1,342	)
Derivatives expense	$	45,275		$	170,750	

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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 March 31, 2012:

				Contract Prices(2)			
		Type of			Weighted Average Price		
Year	Months	Contract	Volume(1)	Range	Swap	Floor	Ceiling
Oil Contracts:							
2012	Apr – June	Swap	625	$ 80.28 – 81.75	$ 81.04	$ —	$ —
		Collar	53,000	70.00 – 137.50	—	70.00	119.44
		Put	625	65.00 – 65.00	—	65.00	—
	Total Apr – June 2012		54,250				
	July – Sept	Swap	625	$ 80.28 – 81.75	$ 81.04	$ —	$ —
		Collar	53,000	80.00 – 140.65	—	80.00	128.57
		Put	625	65.00 – 65.00	—	65.00	—
	Total July – Sept 2012		54,250				
	Oct – Dec	Swap	625	$ 80.28 – 81.75	$ 81.04	$ —	$ —
		Collar	53,000	80.00 – 140.65	—	80.00	128.57
		Put	625	65.00 – 65.00	—	65.00	—
	Total Oct – Dec 2012		54,250				
2013	Jan – Mar	Swap	—	$ —	$ —	$ —	$ —
		Collar	55,000	70.00 – 117.00	—	70.00	110.32
		Put	—	—	—	—	—
	Total Jan – Mar 2013		55,000				
	Apr – June	Swap	—	$ —	$ —	$ —	$ —
		Collar	50,000	75.00 – 124.20	—	75.00	116.92
		Put	—	—	—	—	—
	Total Apr – June 2013		50,000				

July – Sept	Swap	—	$ —	$ —	$ —	$ —
	Collar	50,000	75.00 – 133.10	—	75.00	122.14
	Put	—	—	—	—	—
	Total July – Sept 2013	50,000				
Oct – Dec	Swap	—	$ —	$ —	$ —	$ —
	Collar	18,000	80.00 – 127.50	—	80.00	126.63
	Put	—	—	—	—	—
	Total Oct – Dec 2013	18,000				

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Notes to Unaudited Condensed Consolidated Financial Statements

Year	Months	Type of Contract	Volume(1)	Contract Prices(2) Range	Weighted Average Price Swap	Floor	Ceiling
Natural Gas Contracts:							
2012	Apr – Dec	Swap	20,000	$ 6.30 – 6.85	$ 6.53	$ —	$ —
		Collar	—	—	—	—	—
		Put	—	—	—	—	—
	Total Apr – Dec 2012		20,000				

(1) Contract volumes are stated in BBl/d and MMBtu/d for oil and natural gas contracts, respectively.

(2) Contract prices are stated in $/BBl and $/MMBtu for oil and natural gas contracts, respectively.

Additional Disclosures about Derivative Instruments

At March 31, 2012 and December 31, 2011, we had derivative financial instruments recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

In thousands Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) March 31, 2012	December 31, 2011
Derivatives not designated as hedging instruments:			
Derivative asset			
Crude oil contracts	Derivative assets – current	$ 705	$ 23,452
Natural gas contracts	Derivative assets – current	22,310	23,950
Crude oil contracts	Derivative assets – long-term	1,245	29
Derivative liability			
Crude oil contracts	Derivative liabilities – current	(40,212)	(22,610)
Deferred premiums(1)	Derivative liabilities – current	(1,760)	(3,913)
Crude oil contracts	Derivative liabilities – long-term	(22,013)	(18,702)
Deferred premiums(1)	Derivative liabilities – long-term	—	(170)
Total derivatives not designated as hedging instruments		$ (39,725)	$ 2,036

(1)

Deferred premiums payable relate to various oil and natural gas floor contracts and are payable on a monthly basis through January 2013.

Note 5. Fair Value Measurements

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.

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

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:

- 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. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing. The Company's costless-collars are valued using the Black-Scholes model, an industry standard option valuation model, that takes into account inputs such as contractual prices for the underlying instruments, including maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, 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.

- 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 (i.e., Houston ship channel). The Company's basis swaps are estimated using discounted cash flow calculations based upon forward commodity price curves. Significant increases or decreases in forward commodity price curves would result in a significantly higher or lower fair value measurement.

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and Denbury's credit quality for liability positions. Denbury uses 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
March 31, 2012				
Assets				
Oil and natural gas derivative contracts	$ —	$ 1,950	$ 22,310	$ 24,260
Liabilities				
Oil and natural gas derivative contracts	—	(62,225)	—	(62,225)
Total	$ —	$ (60,275)	$ 22,310	$ (37,965)
December 31, 2011				
Assets				

Short-term investments	$	86,682		$	—		$	—	$	86,682	
Oil and natural gas derivative contracts		—			23,481			23,950		47,431	
Liabilities											
Oil and natural gas derivative contracts		—			(41,312	)		—		(41,312	)
Total	$	86,682		$	(17,831	)	$	23,950	$	92,801	

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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 expense" in the accompanying Unaudited Condensed Consolidated Statements of Operations.

Level 3 Fair Value Measurements

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following table summarizes the changes in the fair value of our Level 3 assets for the three months ended March 31, 2012 and 2011:

In thousands	Three Months Ended March 31, 2012	2011
Balance, beginning of period	$ 23,950	$ 16,478
Unrealized gains on commodity derivative contracts included in earnings	5,400	310
Payments on settlement of commodity derivative contracts	(7,040)	(1,442)
Balance, end of period	$ 22,310	$ 15,346

We utilize an income approach to value our natural gas swap arrangements, generally the industry standard valuation technique for a commodity swap contract. We obtain and ensure the appropriateness of the natural gas forward pricing curve, the most significant input to the calculation, and the fair value estimate is prepared and reviewed on a quarterly basis.

The following table details fair value inputs related to our level 3 financial measurements:

In thousands	Fair Value at 3/31/2012	Valuation Technique(s)	Unobservable Input	Range
Oil and natural gas derivative contracts	$ 22,310	Discounted Cash Flow	Forward commodity price curve	(a)

(a) The derivative instruments detailed in this category include non-exchange-traded natural gas derivatives swaps that are valued based on regional pricing other than NYMEX. The regional pricing sources utilized for these instruments include the following (forward pricing ranges represent the high and low price expected to be received within the settlement period):

Pricing Index	Settlement Period	Forward Pricing Range
TETCO M1	4/1/2012 – 12/31/2012	$2.09/MMBtu – $3.21/MMBtu
Houston Ship Channel	4/1/2012 – 12/31/2012	$2.06/MMBtu – $3.09/MMBtu
Natural Gas – Midcontinent	4/1/2012 – 12/31/2012	$1.98/MMBtu – $3.05/MMBtu

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

As of December 31, 2011, we had invested a total of $13.8 million in the preferred stock of Faustina Hydrogen Products LLC, a company created to develop a proposed gasification plant from which CO2 would be produced as a byproduct and used by Denbury in its tertiary oil operations. The investment was recorded at cost, together with a $1.3 million receivable for accrued dividends receivable. The developer of the proposed plant was soliciting other potential investors for the project, and as of December 31, 2011, a third-party was actively engaged in due diligence. During 2012, a key investor and participant in the project announced its intent to abandon its investment in the proposed plant. As a result, due diligence by the potential third party investor ceased. Absent the key investor, we believe it is unlikely the plant will be constructed and therefore, it is also unlikely our investment will generate future cash flows. Accordingly, we recorded a $15.1 million impairment charge for this investment during the first quarter of 2012, which is classified as "Impairment of assets" in the Unaudited Condensed Consolidated Statements of Operations. The inputs used to determine fair value of the investment included the projected future cash flows of the plant and risk-adjusted rate of return that we estimated would be used by a market participant in valuing the asset. These inputs are unobservable within the marketplace and therefore considered level 3 within the fair value hierarchy. However, as there are currently no expected future cash flows associated with the plant, the fair value was determined to be $0.

Other Fair Value Measurements

The carrying value of our Bank Credit Facility approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our senior subordinated notes as of March 31, 2012 and December 31, 2011 is $2,255.5 million and $2,253.2 million, respectively. The fair value hierarchy for long-term debt is primarily Level 1 (quoted prices for identical assets in active markets). We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 6. Commitments and Contingencies

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. We are also 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. Currently, we have no material assessments for potential taxes.

Note 7. Related Party

During the first quarter of 2012, we purchased and marketed $1.2 million of oil produced by a privately-held entity of which a member of our Board of Directors serves as chairman of the board. The oil purchased under this agreement is related to the non-core assets in central and southern Mississippi and in southern Louisiana (see further discussion in Note 2, Acquisitions and Divestitures) sold to this same entity. We are under no obligation to purchase oil under this agreement.

In addition, during the first quarter of 2012, we entered into a sublease of excess office space at our former corporate headquarters with the same privately-held entity. The sublease provides for payment of $2.4 million in lease rentals to us over the lease term, which expires on July 31, 2016. During the first quarter of 2012, we recorded $27 thousand in lease income related to the new sublease arrangement, which is classified as "Interest income and other income" in the Unaudited Condensed Consolidated Statements of Operations.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 8. Subsequent Events

Sale of Non-Core Assets

On April 11, 2012, we announced that we had entered into an agreement and closed on the sale of certain non-operated assets in the Paradox Basin of Utah for $75 million. The sale had an effective date of January 1, 2012 and proceeds received after consideration of preliminary closing adjustments totaled $72.4 million. Preliminary closing adjustments include operating net revenues after January 1, 2012, net of capital expenditures, along with other purchase price adjustments.

Amendment to Bank Credit Agreement

During April 2012, we entered into an amendment to our Bank Credit Agreement (see Note 3, Long-Term Debt).

Pending Acquisition of Thompson Field

In April 2012, we entered into an agreement to purchase a nearly 100% working interest and 84.7% net revenue interest in Thompson Field located in southeast Texas for approximately $360 million in cash. Under the agreement, the seller will hold approximately a 5% net revenue interest beginning when average monthly tertiary oil production exceeds 3,000 Bbls/d. Thompson Field is a significant potential tertiary oil flood located approximately 18 miles west of our Hastings Field, our most recent CO2 flood. The acquisition is expected to close in June 2012.

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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, 2011 (the "Form 10-K"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Form 10-K. Any terms used but not defined herein 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 Part II of this report, along with Forward-Looking Information at the end of this Item 2 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 combined oil and natural gas producer in both Mississippi and Montana, own the largest CO2 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 CO2 tertiary recovery operations.

Operating Highlights

We recognized net income of $113.5 million, or $0.29 per basic common share, during the first quarter of 2012 compared to a net loss of $14.2 million, or $0.04 per basic common share, during the first quarter of 2011. This increase in net income between the two periods is primarily attributable to:

- an increase in oil and natural gas revenues of $127.3 million resulting from increased production ($69.4 million) and higher realized commodity prices ($57.9 million); and

- a decrease in expenses of $71.3 million, the largest of which was a reduction of the non-cash loss in the fair value of the Company's commodity derivative contracts of $128.3 million, principally due to the change in NYMEX oil futures prices relative to our derivative contracts in place during each period, offset in part by other expense increases.

During the first quarter of 2012, our oil and natural gas production, which was 93% oil, averaged 71,532 BOE/d compared to 63,604 BOE/d produced during the first quarter of 2011. This 12% increase in production is primarily attributable to increases in our Bakken and tertiary oil production, partially offset by normal declines in most of our other non-tertiary properties. After adjusting quarterly production in both periods to exclude production from non-core properties which were sold in 2012 (see Sale of Non-Core Assets below), continuing production in the first quarter of 2012 increased 14% over production in the comparable prior year quarter and 7% sequentially over levels in the fourth quarter of 2011. Our tertiary oil production averaged 33,257 Bbls/d during the first quarter of 2012, an increase of 8% over the 30,825 Bbls/d produced during the first quarter of 2011 and 7% over fourth quarter 2011 levels. Our Bakken oil production averaged 15,114 BOE/d during the first quarter of 2012, an increase of 164% over production of 5,728 BOE/d during the first quarter of 2011, and 29% over levels in the fourth quarter of 2011. See Results of Operations — CO2 Operations and Results of Operations — Operating Results — Production for more information.

Oil prices during the first quarter of 2012 were considerably higher than prices during the first quarter of 2011, with average NYMEX oil prices averaging $102.89 per Bbl in the first quarter of 2012, compared to average NYMEX prices of $94.26 per Bbl during the first quarter of 2011. Our average realized oil price received per barrel, excluding the impact of commodity derivative contracts, was $102.52 per Bbl during the first quarter of 2012, compared to $93.67 per Bbl during the first quarter of 2011, a 9% increase between the comparative periods. See Results of Operations – Operating Results – Oil and Natural Gas Revenues below for more information on our oil prices received and differentials to NYMEX prices.

Sale of Investment in Vanguard Natural Resources LLC

On January 19, 2012, we sold our investment in Vanguard Natural Resources LLC ("Vanguard") common units for cash consideration of $83.5 million, net of related transaction fees. The investment was originally acquired as partial consideration for the sale of our interests in Encore Energy Partners LP on December 31, 2010. In connection with the sale, during the first quarter of 2012 we recorded a pretax $3.1 million loss which is classified as "Other expenses" in the Unaudited Condensed Consolidated Statements of Operations. The $3.1 million loss represents the difference between the net proceeds received from the sale and the carrying amount of the investment at December 31, 2011.

Sale of Non-Core Assets

On January 10, 2012, we entered into an agreement to sell certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155 million. On February 29, 2012, we closed the sale for net proceeds of $144.8 million, after preliminary closing adjustments. The sale had an effective date of December 1, 2011 and consequently operating net revenues after December 1, 2011, net of capital expenditures, along with any other purchase price adjustments, reduced the selling price. We did not record a gain or loss on the sale in accordance with the full cost method of accounting.

On April 11, 2012, we announced that we had entered into an agreement and closed the sale of non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah for $75 million. The sale had an effective date of January 1, 2012 and proceeds received after consideration of preliminary closing adjustments totaled $72.4 million.

Addition of Proved Oil and Natural Gas Reserves

During the first quarter of 2012, we added 18.3 MMBOE of estimated proved reserves, including 14.0 MMBOE at Oyster Bayou Field based on the field's recent response to CO_2 injections, and 4.3 MMBOE due to further development in the Bakken. These increases were partially offset by the disposition of 6.6 MMBOE of reserves associated with certain non-core Gulf Coast assets we sold in February 2012, as discussed above.

Pending Acquisition of Thompson Field

On April 24, 2012, we entered into an agreement to purchase a nearly 100% working interest and 84.7% net revenue interest in Thompson Field located in southeast Texas for approximately $360 million in cash. Under the agreement, the seller will hold approximately a 5% net revenue interest when average monthly tertiary oil production exceeds 3,000 Bbls/d. Thompson Field is a significant potential tertiary oil flood and is located approximately 18 miles west of our Hastings Field. Net to Denbury's interest, Thompson Field is producing approximately 2,200 Bbls/d of oil, roughly equivalent to the daily production volumes of our non-core assets divested to date in 2012, as discussed above, all of which is non-tertiary production. The sale has an effective date of June 1, 2012 and is expected to close in June 2012.

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

Capital Resources and Liquidity

We recently increased our projected 2012 capital budget from $1.35 billion to $1.5 billion based on higher than previously estimated cash flows as a result of better than expected commodity prices and production. We allocated $80 million of our capital budget to further develop the Bakken, $65 million to tertiary oilfield expenditures (primarily in the Hastings and Bell Creek fields) and the remainder to other capital spending projects. Our capital budget of $1.5 billion excludes estimated equipment leases ($75 million), acquisitions, capitalized interest and start-up costs associated with our new tertiary floods. Our current 2012 capital budget includes the following:

- $430 million allocated for tertiary oil field expenditures;
- $480 million for development of our Bakken properties;
- $290 million for pipeline construction;
- $200 million to be spent on CO_2sources; and
- $100 million to be spent in all other areas.

Based on oil and natural gas prices in early May 2012 and our current production forecasts, we estimate that our 2012 capital budget (including capitalized interest and tertiary start-up costs) will be approximately $100 to $200 million greater than our 2012 anticipated cash flow from operations. We plan to fund any shortfall between our cash flow from operations and our capital spending with our asset sales and borrowings under our Bank Credit Facility.

During the first three months of 2012, we incurred capital expenditures of approximately $319.8 million, net of equipment lease recoveries of $21.0 million. Additionally, we have capitalized interest and tertiary start-up costs which are not included in the above mentioned amounts. See additional detail on our expenditures in the table below.

During the first four months of 2012, we received net proceeds from non-core oil and natural gas asset divestitures of $217.2 million ($144.8 million at March 31, 2012 and $72.4 million during April 2012), $212.5 million of which are being held by a qualified intermediary to facilitate an anticipated like-kind exchange transaction. We plan to use these proceeds, together with borrowings under our Bank Credit Facility, to fund the $360 million acquisition of Thompson Field, which is expected to close in early June 2012. See Sale of Non-Core Assets and Pending Acquisition of Thompson Field discussed above. In structuring these transactions as a like-kind exchange for income tax purposes, we anticipate deferral of a majority of the taxable gain recognized on the sale of the non-core assets. Such amounts are classified as "Restricted cash" on the Unaudited Condensed Consolidated Balance Sheet.

In October 2011, we commenced a share repurchase program for up to $500 million of Denbury common stock. To date we have only repurchased $195.2 million (all during the fourth quarter of 2011). Any further share repurchases during 2012 will be determined based on various parameters; therefore, it is uncertain whether or not we will make additional share repurchases of Denbury common stock under this program in the remainder of 2012.

We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital spending up or down depending on cash flows; however, any such reduction in capital spending could reduce our anticipated production levels in future years. For 2012 and certain future years, we have contracted for certain capital expenditures; therefore, we cannot eliminate all of our capital commitments without penalties (refer to Management's Discussion and Analysis – Capital Resources and Liquidity – Off-Balance Sheet Arrangements — Commitments and Obligations in the Form 10-K). In addition to the potential flexibility in our capital spending plans, as of March 31, 2012, we had approximately $1.2 billion of unused liquidity under our Bank Credit Facility and have oil price floors in place through 2013 (see Note 4, Derivative Instruments, 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. Also, we currently believe we could significantly expand our borrowing base beyond the current $1.6 billion if we desired to do so.

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Denbury Resources Inc.

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Capital Expenditure Summary

The following table of capital expenditures includes accrued capital for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,	
In thousands	2012	2011
Capital expenditures by project:		
Tertiary oil fields	$113,578	$100,984
Bakken	122,500	61,358
CO2 pipelines	14,151	3,497
CO2 properties	18,161	20,306
Other areas	72,373	46,310
Capital expenditures before acquisitions and capitalized interest	340,763	232,455
Less: recoveries from sale/leaseback transactions	(21,002)	(2,445)
Net capital expenditures excluding acquisitions and capitalized interest	319,761	230,010
Acquisitions:		
Property acquisitions	1,234	29,801
Capitalized interest	19,445	10,957
Capital expenditures, net of sale/leaseback transactions	$340,440	$270,768

Our capital expenditures for the first three months of 2012 were funded with $291.7 million of cash flow from operations and the remainder with borrowings under our Bank Credit Facility. Our capital expenditures for the first three months of 2011 were funded with $124.8 million of cash flow from operations and the remainder with cash on hand at the beginning of the period.

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.

Our commitments and obligations consist of those detailed as of December 31, 2011 in the Form 10-K under Management's Discussion and Analysis of Financial Condition and Results of Operations – Off-Balance Sheet Arrangements – Commitments and Obligations.

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

Results of Operations

CO2 Operations

Our focus on CO2operations is the primary strategy of our business and operations. We believe there are significant additional oil reserves and production that can be obtained through the use of CO2, and we have outlined certain of this estimated potential in our Form 10-K 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 CO2 Operations contained in our Form 10-K for further information regarding these matters.

During the first quarter of 2012, our CO2 production at Jackson Dome averaged 1,047 MMcf/d, compared to an average of 1,021 MMcf/d produced during the first quarter of 2011 and 1,024 MMcf/d produced during the fourth quarter of 2011. We used 92% of this production, or 964 MMcf/d, in our tertiary operations during the first quarter of 2012, and sold the balance to our industrial customers or to Genesis Energy, L.P. 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 Form 10-K for further discussion of our CO2 delivery obligations. We believe we have sufficient CO2reserves to develop our current Gulf Coast enhanced oil recovery program, and we continue to drill additional wells to increase our productive capability and to test the significant probable and possible reserves at Jackson Dome. At December 31, 2011, our proven CO2 reserves at Jackson Dome were approximately 6.7 Tcf.

We spent approximately $0.28 per Mcf in operating expenses to produce our CO2 during the first quarter of 2012, which costs averaged $0.25 per Mcf during the first quarter of 2011 and the fourth quarter of 2011. This increase in the rate from the prior year quarters is due primarily to increased CO2 royalty expense (which is tied to oil prices) and an increase in lease operating expense charges.

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The following table summarizes our tertiary oil production and tertiary lease operating expense per barrel for each quarter in 2011 and the first quarter of 2012:

Tertiary Oil Field	Average Daily Production (Bbl/d) First Quarter 2011	Second Quarter 2011	Third Quarter 2011	Fourth Quarter 2011	First Quarter 2012
Phase 1:					
Brookhaven	3,664	3,213	3,030	3,121	3,014
McComb area	2,161	1,983	2,005	1,843	1,746
Mallalieu area	2,925	2,646	2,620	2,587	2,585
Other	3,290	3,196	2,879	2,749	2,500
Phase 2:					
Heidelberg	3,374	3,548	3,141	3,728	3,583
Eucutta	3,247	3,114	2,985	3,139	3,090
Soso	2,582	2,317	2,331	2,162	2,063
Martinville	500	416	453	481	551
Phase 3:					
Tinsley	6,567	6,990	7,075	6,338	7,297
Phase 4:					
Cranfield	991	1,085	1,214	1,200	1,152
Phase 5:					
Delhi	1,524	2,263	3,358	3,778	4,181
Phase 7:(1)					
Hastings	—	—	—	—	618
Phase 8:					
Oyster Bayou	—	—	—	18	877
Total tertiary oil production (Bbl/d)	30,825	30,771	31,091	31,144	33,257
Tertiary lease operating expense per Bbl	$ 24.93	$ 22.87	$ 24.91	$ 23.59	$ 26.74

(1) As of March 31, 2012, we did not have any tertiary production from our fields in Phase 6, Citronelle Field, which will require an extension to the Free State CO2 Pipeline or another pipeline, depending on the ultimate CO2 source for this field, the timing of which is uncertain.

Oil production from our tertiary operations increased to an average of 33,257 Bbls/d during the first quarter of 2012, an 8% increase over our first quarter 2011 tertiary production levels, primarily due to production growth in response to continued expansion of the tertiary floods in the Heidelberg, Tinsley, Cranfield and Delhi Fields and production at our Oyster Bayou and Hastings CO2 fields, which two fields experienced their initial tertiary production response in late December 2011 and early January 2012, respectively. Offsetting first quarter production gains were declines in our more mature Phase 1 and Phase 2 fields (except Heidelberg and Martinville). Production during the first quarter of 2012 increased 2,113 Bbls/d compared to fourth quarter 2011 levels primarily due to production increases at Tinsley, Delhi, Oyster Bayou and Hastings fields.

The production growth rate at a tertiary flood can vary 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 of 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. At Heidelberg Field, during the second half of 2011 and the first quarter of 2012, we modified 39 wells and 18 wells, respectively, in order to address conformance issues (i.e., to control the flow of the CO_2 to the desired geologic zone within the reservoir). While tertiary production at Heidelberg Field decreased slightly during the first quarter of 2012 compared to levels in the fourth quarter of 2011, we are seeing improvement in the gas / oil ratio in West Heidelberg, an indication that the conformance is working and that we are contacting the oil with CO_2. At Tinsley Field, during the third quarter of 2011, we stopped CO_2 injections in parts of the field in order to address issues with wells that were improperly plugged by prior operators. Full CO_2 injections resumed during the first quarter of 2012 in Tinsley Field, which has responded with a 15% increase in sequential quarter production.

During the first quarter of 2012, operating costs for our tertiary properties averaged $26.74 per Bbl, compared to our first quarter of 2011 average cost of $24.93 per Bbl and a fourth quarter of 2011 average cost of $23.59 per Bbl. The per-barrel increase in the most recent quarter was primarily due to our new tertiary floods at Oyster Bayou and Hastings fields and higher CO_2 injection costs resulting from increased CO_2 injection volumes and higher oil prices, to which CO_2 costs are partially tied. During the first quarter of 2012, Oyster Bayou and Hastings Fields entered the production stage and, as a result, injection costs associated with this production began to be expensed (as compared to being capitalized when in the development phase). These two new tertiary floods account for a significant portion of our overall higher per-barrel tertiary operating expenses in the first quarter of 2012 because of the relatively low production at these two new floods in relation to the operating costs being expensed at these fields. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when lease operating expense per barrel will again increase.

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Denbury Resources Inc.

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

Operating Results

Certain of our operating results and statistics for the first three months of 2012 and 2011 are included in the following table:

	Three Months Ended March 31,	
In thousands, except per share and unit data	2012	2011
Operating results		
Net income (loss)	$113,467	$(14,190)
Net income (loss) per common share – basic	0.29	(0.04)
Net income (loss) per common share – diluted	0.29	(0.04)
Net cash provided by operating activities	291,654	124,832
Average daily production volumes		
Bbls/d	66,857	58,460
Mcf/d	28,052	30,866
BOE/d(1)	71,532	63,604
Operating revenues		
Oil sales	$623,706	$492,838
Natural gas sales	9,795	13,354
Total oil and natural gas sales	$633,501	$506,192
Commodity derivative contracts(2)		
Cash receipt (payment) on settlement of commodity derivative contracts	$(1,190)	$1,588
Non-cash fair value adjustment expense	(44,085)	(172,338)
Total expense from commodity derivative contracts	$(45,275)	$(170,750)
Unit prices – excluding impact of derivative settlements		
Oil price per Bbl	$102.52	$93.67
Natural gas price per Mcf	3.84	4.81
Unit prices – including impact of derivative settlements(2)		
Oil price per Bbl	$101.16	$92.72
Natural gas price per Mcf	6.59	7.19
Oil and natural gas operating expenses		
Lease operating expenses	$137,964	$123,797
Marketing expenses	10,830	5,303
Taxes other than income(3)	43,694	32,483
Oil and natural gas operating revenues and expenses per BOE(1)		
Oil and natural gas revenues	$97.32	$88.42
Lease operating expenses	21.19	21.63
Marketing expenses	1.66	0.93
Taxes other than income	6.71	5.67
Non-tertiary CO2 revenues and expenses:		
CO2 sales and transportation fees	$6,795	$4,924
CO2 discovery and operating expenses(4)	(6,205)	(1,946)
CO2 revenue and expenses, net	$590	$2,978

(1)

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

(2) See also Item 3. Quantitative and Qualitative Disclosures about Market Risk below for information concerning the Company's derivative transactions.

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(3) Includes \$2.6 million and \$1.5 million of franchise taxes and property taxes on office buildings as of March 31, 2012 and 2011, respectively.

(4) Includes \$4.9 million of exploratory drilling costs during the three months ended March 31, 2012. We incurred no exploratory drilling costs during the three months ended March 31, 2011.

Production

Average daily production by area for each of the four quarters of 2011 and for the first quarter of 2012 are shown below:

	Average Daily Production (BOE/d)				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter
Operating Area	2011	2011	2011	2011	2012
Gulf Coast region:					
Tertiary oil fields	30,825	30,771	31,091	31,144	33,257
Non-tertiary fields:					
Mississippi	5,930	5,642	5,636	4,746	4,573
Texas	4,371	4,202	4,096	3,868	3,674
Louisiana	511	454	47	141	191
Alabama and other	1,020	1,079	1,064	1,031	1,090
Total Gulf Coast region	42,657	42,148	41,934	40,930	42,785
Rocky Mountain region:					
Cedar Creek Anticline	9,163	8,925	8,930	8,858	8,496
Bakken	5,728	7,626	9,976	11,743	15,114
Bell Creek	890	936	889	840	859
Other	2,613	2,693	2,689	2,533	2,516
Total Rocky Mountain region	18,394	20,180	22,484	23,974	26,985
Total Continuing Production	61,051	62,328	64,418	64,904	69,770
Properties disposed or to be disposed:					
Gulf Coast assets(1)	1,918	1,901	1,732	1,677	1,054
Paradox assets(2)	635	690	680	653	708
Total Production	63,604	64,919	66,830	67,234	71,532

(1) Includes production from certain non-core Gulf Coast assets sold in late February 2012.

(2) Includes production from certain non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012.

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Continuing production during the three months ended March 31, 2012 was 69,770 BOE/d, a 14% increase over continuing production during the first three months 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 CO2 Operations above), offset by normal declines in most of our other non-tertiary properties. Total production increased 12% between the first quarters of 2011 and 2012, and includes production related to certain non-core Gulf Coast assets sold in February 2012 and non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012. Our production from the Cedar Creek Anticline is on a general decline, but also reflects a larger decline in periods of increasing prices due to a net profits interest associated with this production; therefore, a portion of the decline in production at this field is related to the increase in oil prices during the last twelve months.

Production from our Bakken properties averaged 15,114 BOE/d in the first quarter of 2012, a 164% increase from first quarter 2011 levels and an increase of 29% compared to fourth quarter 2011 production levels. The production increases in the Bakken are due to the acceleration of our drilling activities in the area in 2011. During 2011, we operated as many as seven drilling rigs in the Bakken, decreasing to six operated drilling rigs by the end of 2011. We plan to reduce the rig count in the Bakken to four by mid-2012, which will likely begin to slow the rate of Bakken production growth. During the first three months of 2012, we completed 13 operated wells in the Bakken.

Our production during the three months ended March 31, 2012 was 93% oil, which remained consistent with oil production of 92% during the three months ended March 31, 2011.

Oil and Natural Gas Revenues. Due to the increases in oil prices and production between the first three months of 2011 and 2012, our oil and natural gas revenues increased 25% during the first quarter of 2012 as compared to revenues in the first quarter of 2011. These changes in oil and natural gas revenues, excluding any impact of our commodity derivative contracts, are reflected in the following table:

In thousands	Three Months Ended March 31, 2012 vs. 2011 Increase in Revenues	Percentage Increase in Revenues
Change in oil and natural gas revenues due to:		
Increase in production	$ 69,422	14%
Increase in commodity prices	57,887	11%
Total increase in oil and natural gas revenues	$ 127,309	25%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31, 2012	2011
Net Realized Prices:		
Oil price per Bbl	$102.52	$93.67
Natural gas price per Mcf	3.84	4.81
Price per BOE	97.32	88.42

NYMEX Differentials:		
Oil per Bbl	$(0.37)	$(0.59)
Natural gas per Mcf	1.32	0.61

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As reflected in the table above, our net realized oil prices increased in the first quarter of 2012 compared to those received during the first quarter of 2011, while oil differentials improved slightly between the two periods. Company-wide oil price differentials in the first quarter of 2012 were $0.37 per Bbl below NYMEX, compared to an average differential of $0.59 per Bbl below NYMEX in the first quarter of 2011 and $9.14 per Bbl above NYMEX in the fourth quarter of 2011. Our favorable NYMEX differential during the fourth quarter of 2011 was primarily due to the favorable differential for crude oil sold under Light Louisiana Sweet ("LLS") index prices. Prices received in a regional market can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. NYMEX pricing, which has long been a benchmark price that reflects the economics in the U.S. midcontinent market, has been influenced in the recent past by significant increases in supply. Alternatively, the LLS market is reflective of market economics in the Gulf Coast region, where both foreign and domestic oil is bought and sold, and correlates more closely to global oil prices. During the first quarter of 2012, the Company sold approximately 40% of its crude oil at prices based on the LLS index price, approximately 20% at prices tied to a combination of the LLS index price and other indexes, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. This LLS-to-NYMEX differential averaged a positive $12.55 per Bbl on a trade-month basis for the first quarter of 2012, compared to a positive $9.28 per Bbl differential in the first quarter of 2011 and a positive $23.36 per Bbl differential in the fourth quarter of 2011. While this differential is significant in the pricing for our oil production, other factors may prevent us from realizing the full differential. As indicated by the above variations, the LLS-to-NYMEX differential is volatile and has been at historically high levels in recent periods, which may not continue. The differential for oil production sold in the Bakken averaged $16.96 per Bbl below NYMEX in the first quarter of 2012, as compared to an average differential of $11.55 per Bbl below NYMEX in the first quarter of 2011 and $8.42 per Bbl below NYMEX in the fourth quarter of 2011. Oil in the Bakken region sold at a significant discount during the first quarter of 2012 due to increased production in the area coupled with limited transportation infrastructure.

Commodity Derivative Contracts. The following tables summarize the impact our commodity derivative contracts had on our operating results for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,					
	2012	2011	2012	2011	2012	2011
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value loss	$(42,445)	$(167,064)	$(1,640)	$(5,274)	$(44,085)	$(172,338)
Cash settlement receipts (payments)	(8,230)	(5,028)	7,040	6,616	(1,190)	1,588
Total	$(50,675)	$(172,092)	$5,400	$1,342	$(45,275)	$(170,750)

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. Lease operating expenses were $138.0 million during the three months ended March 31, 2012, an increase of $14.2 million (11%) from the same period in 2011. This increase is primarily attributable to a 17% increase in our tertiary operating expenses, from $69.2 million to $80.9 million. Lease operating expenses increased $13.8 million from $124.2 million during the fourth quarter of 2011, also due to increased lease operating expense on our tertiary properties. See discussion of tertiary operating expenses above under CO2 Operations. The increase in tertiary lease operating expense was partially offset in both comparative periods by lower lease operating expense on our non-tertiary properties, primarily due to the divestiture of certain non-core Gulf Coast properties during the first quarter of 2012.

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Lease operating expense averaged $21.19 per BOE for the three months ended March 31, 2012, compared to $21.63 per BOE for the same period in 2011 and $20.08 per BOE during the fourth quarter of 2011. Lower non-tertiary operating expenses per BOE during both comparative periods is primarily due to increased Bakken production and the sale of our non-core Gulf Coast properties during the first quarter of 2012, which had a higher operating cost per BOE compared to the average of our other properties. Our tertiary operating costs, which have historically been higher than our Company-wide operating costs, averaged $26.74 per Bbl during the three months ended March 31, 2012, compared to $24.93 per Bbl for the same period in 2011. See CO2 Operations for a more detailed discussion.

Taxes other than income, which includes ad valorem, production and franchise taxes, averaged $6.71 per BOE for the three months ended March 31, 2012, compared to $5.67 per BOE for the same period in 2011. The increase between periods is largely attributable to an increase in production taxes, which generally fluctuate in line with oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Three Months Ended March 31,	
In thousands, except per BOE data and employees	2012	2011
Administrative costs	$ 74,060	$ 67,328
Stock-based compensation	10,594	11,337
Operator labor and overhead recovery charges	(35,624)	(29,269)
Capitalized exploration and development costs	(12,423)	(7,077)
Net G&A expense	$ 36,607	$ 42,319
G&A per BOE:		
Administrative costs, net	$ 4.55	$ 5.79
Stock-based compensation, net	1.07	1.60
Net G&A expense	$ 5.62	$ 7.39
Employees as of March 31	1,326	1,182

Net G&A expense during the first quarter of 2012 declined on both an absolute dollar and per BOE basis compared to levels in the first quarter of 2011, as higher administrative costs were more than offset by increased operator labor and overhead recovery charges and capitalized exploration and developments costs. The 24% decrease in G&A per BOE between the two periods was further impacted by higher production.

Administrative costs increased $6.7 million (10%) during the first quarter of 2012 compared to the same period in 2011. The increase between the comparative first quarters was primarily due to an increase in compensation-related costs due to an increase in headcount and salaries, which we consider necessary to remain competitive in our industry. The increase in compensation expense was partially offset by a reduction in third-party professional services, corporate office expenses and insurance.

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 and drilling activities, additional tertiary operations and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 22% during the three months ended

March 31, 2012 compared to the same period in 2011. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

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Interest and Financing Expenses

In thousands, except per BOE data and interest rates	Three Months Ended March 31, 2012	2011
Cash interest expense	$52,033	$54,206
Non-cash interest expense	3,726	5,528
Less: capitalized interest	(19,445)	(10,957)
Interest expense	$36,314	$48,777
Interest income and other income	$4,820	$3,049
Net cash interest expense and other income per BOE (1)	$4.27	$7.10
Average debt outstanding	$2,744,926	$2,514,621
Average interest rate (2)	7.6 %	8.6 %

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

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

The increase in capitalized interest between the first quarters of 2011 and 2012 relates primarily to incremental capitalized interest on the Hastings and Conroe field CO_2 floods, and the ongoing Riley Ridge and Greencore Pipeline construction. We expect capitalization of interest to decrease later in 2012 due to the completion of currently ongoing development projects.

Depletion, Depreciation, and Amortization ("DD&A")

In thousands, except per BOE data	Three Months Ended March 31, 2012	2011
Depletion and depreciation of oil and natural gas properties	$107,055	$82,086
Depletion and depreciation of CO_2 properties	5,110	4,590
Asset retirement obligations	1,695	1,563
Depreciation of other fixed assets	7,035	5,355
Total DD&A	$120,895	$93,594
DD&A per BOE:		
Oil and natural gas properties	$16.71	$14.61
CO_2 and other fixed assets	1.86	1.74
Total DD&A cost per BOE	$18.57	$16.35

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. Depletion of oil and natural gas properties increased 30% on an absolute-dollar basis and 14% on a per-BOE basis during the first quarter of 2012 compared to the same period in 2011, primarily due to higher finding costs per barrel associated with the Bakken capital program and upward revisions in estimated future development costs, also primarily related to the Bakken. The increase in DD&A on an absolute-dollar basis was further impacted by increases in production volumes. Depletion of oil and natural gas properties increased 9% on an absolute-dollar basis between the fourth quarter of 2011 and the first quarter of 2012, primarily due to increased production volumes and higher future development costs related to Bakken wells, and increased slightly, by 3%, on a per-BOE basis. The increase in depreciation of other fixed assets is primarily due to incremental pipeline depreciation.

During the first quarter of 2012 we recognized incremental reserves related to our tertiary production at Oyster Bayou Field and development in the Bakken. See Overview – Addition of Proved Oil and Natural Gas Reviews above. We currently expect to book initial proved tertiary reserves for our new tertiary flood at Hastings Field by the end of 2012.

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Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a ceiling test write-down at March 31, 2012; 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, in part, 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, as well as additional capital spent.

Impairment of Assets and Other Expenses

We recognized $17.3 million of impairment charges during the first quarter of 2012. As of December 31, 2011, we had invested $13.8 million in a preferred interest in Faustina Hydrogen Products LLC, an entity created to develop a proposed plant from which we would offtake CO2. The investment was recorded at cost, together with $1.3 million receivable for preferred distributions. The developer of the proposed plant has been soliciting other potential investors for the project, and as of December 31, 2011, a third-party was actively engaged in due diligence. During 2012, a key investor and participant in the project announced its intent to abandon its investment in the proposed plant. As a result, due diligence by the potential third party investor ceased. Absent the key investor, we do not believe our investment will generate future cash flows. Accordingly, we recorded a $15.1 million impairment charge during the first quarter of 2012, which is classified as "Impairment of assets" in the Unaudited Condensed Consolidated Statements of Operations. The remaining $2.2 million asset impairment charge during the first quarter of 2012 relates to additional costs on a potential CO2 source that we do not believe will produce reserves in a quantity or at a cost that would benefit our tertiary oil operations. Accordingly, we impaired the previously capitalized costs related to the development of the property.

Other expenses during the first quarter of 2012 includes a $3.1 million pretax loss on the sale of our investment in Vanguard common units (see First Quarter Operating Highlights above), a $3.9 million charge for our inability to deliver guaranteed quantities of helium under a helium supply arrangement with a third party and a $3.7 million charge to create an allowance for a potentially uncollectible loan receivable acquired in the Encore acquisition. The helium supply agreement, which was assumed by the Company in connection with our purchase of the Riley Ridge Field, contemplated that the Riley Ridge plant would be operational in early 2012. The plant is currently expected to start up during the fourth quarter of 2012. Due to the delayed start up, we will be unable to meet our contractual commitment under the helium supply agreement. We have recorded a charge for $3.9 million, which is our current estimate of the liability. Our obligation under the contract could increase depending on the commencement of helium deliveries during 2012 and other factors; however, in accordance with the supply agreement, the obligation will not exceed $8.0 million during any given year. Other expenses during the first quarter of 2011 included transaction and other costs related to our merger with Encore Acquisition Company.

Income Taxes

In thousands, except per BOE amounts and tax rates	Three Months Ended March 31, 2012	2011
Current income tax expense (benefit)	$ 28,708	$ (848)
Deferred income tax expense (benefit)	37,137	(7,908)
Total income tax expense (benefit)	$ 65,845	$ (8,756)
Average income tax expense (benefit) per BOE	$ 10.12	$ (1.53)
Effective tax rate	36.7 %	38.2 %

Our income taxes are based on an estimated statutory rate of approximately 38%. Our effective tax rate for the first quarter of 2012 was slightly lower than our statutory rate, primarily due to the sale of our Vanguard common units in January 2012, which allowed us to utilize a larger amount of preferential tax benefits due to the higher taxable income from the sale, offset in part by nondeductible expenses. Our effective tax rate for the first quarter of 2011 was higher than our statutory rate primarily due to nondeductible compensation. The amount recorded as current income tax expense represents our federal alternative minimum taxes that we cannot offset with enhanced oil recovery credits and our state income taxes during the three months ended March 31, 2012 and 2011.

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As of December 31, 2011, we had an estimated $53.4 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2012 or future years. The enhanced oil recovery credits do not begin to expire until 2023. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we do not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

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.

Per BOE data	Three Months Ended March 31, 2012	2011
Oil and natural gas revenues	$97.32	$88.42
Gain (loss) on settlements of derivative contracts	(0.18)	0.28
Lease operating expenses	(21.19)	(21.63)
Marketing expenses	(1.66)	(0.93)
Production netback	74.29	66.14
CO2 sales, net of operating expenses	0.08	0.52
Taxes other than income(1)	(6.71)	(5.67)
General and administrative expenses	(5.62)	(7.39)
Net cash interest expense and other income	(4.27)	(7.10)
Other	(3.67)	0.88
Changes in assets and liabilities relating to operations	(9.30)	(25.57)
Cash flow from operations	44.80	21.81
DD&A	(18.57)	(16.35)
Deferred income taxes	(5.71)	1.38
Loss on early extinguishment of debt	—	(2.76)
Non-cash commodity derivative adjustments	(6.78)	(30.11)
Impairment of assets	(2.66)	—
Other non-cash items	6.35	23.55
Net income (loss)	$17.43	$(2.48)

(1) "Taxes other than income" includes production taxes related to oil and natural gas production of $5.51 and $4.84, for the three months ended March 2012 and 2011, respectively.

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 the Form 10-K.

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

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 the section "Management's Discussion and Analysis of Financial Condition and Results of Operations", are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods including the timing and location thereof, acquisition or disposition plans and proposals, development activities, timing of CO2 injections and initial production responses thereto, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO2 reserves, helium reserves, potential reserves, percentages of recoverable original oil in place, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, cost and availability of equipment and services, liquidity, cash flows, availability of capital, borrowing capacity, regulatory matters, prospective legislation affecting the oil and gas industry, 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," "s "assume," "believe," "target," or other words that convey, or are intended to 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 and adversely affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are fluctuations of the prices received or demand for the Company's oil and natural gas; 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; 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; general economic conditions; competition and government regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company's other public reports, filings and public statements including, without limitation, the Form 10-K.

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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. Our Bank Credit Agreement and our senior subordinated notes do not have any triggers or covenants regarding our debt ratings with rating agencies. Borrowings on our Bank Credit Facility, which bear interest at variable rates, expose us to market risk related to changes in interest rates. As of March 31, 2012, our borrowings on our Bank Credit Facility were $445.0 million, with a weighted average interest rate of 2.0%. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense.

The following table presents the principal balances of our debt, by maturity date, as of March 31, 2012:

In thousands, except percentages	2014	2015	2016	2017	2020	2021
Variable rate debt:						
Bank Credit Facility (weighted average interest rate of 2.00% at March 31, 2012)	$—	$—	$445,000	$—	$—	$—
Fixed rate debt:						
9.5% Senior Subordinated Notes due 2016	—	—	224,920	—	—	—
9.75% Senior Subordinated Notes due 2016	—	—	426,350	—	—	—
8.25% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—
6.375% Senior Subordinated Notes due 2021	—	—	—	—	—	400,000
Other Subordinated Notes	1,072	485	—	2,250	—	—

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 approximately a year and a half in the future from the current quarter, 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, to the Unaudited Condensed 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. We only enter into commodity derivative contracts with parties that are lenders under our Bank Credit Facility. 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 March 31, 2012, our commodity derivative contracts were recorded at their fair value, which was a net liability of approximately $38.0 million (excluding $1.8 million of deferred premiums that Denbury is obligated to pay for its derivative contracts, which payments are not subject to changes in commodity prices), a change of approximately $44.1 million from the $6.1 million fair value net asset recorded at December 31, 2011 (excluding $4.1 million of deferred premiums). This change is primarily related to changes in oil futures prices between December 31, 2011 and March 31, 2012.

Based on NYMEX crude oil and natural gas futures prices as of March 31, 2012, 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:

	Receipt / (Payment)	
In thousands	Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
NYMEX futures prices as of March 31, 2012	$(4,171)	$22,672
10% increase in prices	(34,882)	21,353
10% decrease in prices	(2,229)	23,999

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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 Securities Exchange Act of 1934 (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of March 31, 2012, to ensure that information required to be disclosed in the reports the Company files and submits under the Exchange Act 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 its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Evaluation of Changes in Internal Control over Financial Reporting. Under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer, the Company determined that, during the first quarter of fiscal 2012, there were no changes in its internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information with respect to this item is incorporated by reference from the Form 10-K.

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference from Item 1A of the Form 10-K. There have been no material changes to the risk factors since the filing of the 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 first quarter of 2012, made solely in connection with 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
January 2012	192,436	$ 16.65	—	$ —
February 2012	28,938	19.69	—	—
March 2012	133,416	18.32	—	—
Total	354,790	17.52	—	$ —

During the first quarter of 2012, the Company made no repurchases of common stock under its share repurchase program that began in October 2011. See Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity for more information.

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

None

Item 5. Other Information

None

Item 6. Exhibits

Exhibit	Description
4(a)*	Seventh Amendment to Credit Agreement dated as of March 9, 2010, dated as of April 11, 2012, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto.
10(a)* **	Form of 2012 Performance Stock Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(b)* **	Form of 2012 Performance Cash Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(c)* **	Form of 2012 TSR Performance Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

* Filed herewith.
** Compensation arrangements.

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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.

Date: May 10, 2012	/s/ Mark C. Allen Mark C. Allen Senior Vice President and Chief Financial Officer
Date: May 10, 2012	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer