DENBURY RESOURCES INC
Form 10-Q
May 10, 2011

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

(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2011

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

For the transition period from _______ to ________

Commission file number: **001-12935**

DENBURY RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdictions of incorporation or organization)	(I.R.S. Employer Identification No.)
5320 Legacy Drive **Plano, TX**	**75024**
(Address of principal executive offices)	(Zip Code)

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

Not applicable

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o

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

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

Indicate by check mark whether the registrant is a shell company (as defined in 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 29, 2011
Common Stock, $.001 par value	401,887,373

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

	March 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 127,857	$ 381,869
Accrued production receivable	264,150	223,584
Trade and other receivables, net of allowance of $471 and $456, respectively	138,026	114,149
Short-term investments	99,733	93,020
Derivative assets	19,345	24,242
Deferred tax assets	72,552	27,454
Total current assets	721,663	864,318
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	6,238,629	6,042,442
Unevaluated	912,267	870,130
CO_2 and other non-hydrocarbon gases - properties and pipelines	1,940,392	1,901,662
Other property and equipment	132,692	120,641
Less accumulated depletion, depreciation, amortization, and impairment	(2,295,952)	(2,197,517)
Net property and equipment	6,928,028	6,737,358
Derivative assets	9,203	12,919
Goodwill	1,232,418	1,232,418

Other assets		220,107		218,050
Total assets	$	9,111,419	$	9,065,063
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	$	246,145	$	345,998
Oil and gas production payable		161,471		143,145
Derivative liabilities		218,341		78,184
Current maturities of long-term debt		8,446		7,948
Other liabilities		4,070		4,070
Total current liabilities		638,473		579,345
Long-term liabilities				
Long-term debt, net of current portion		2,344,781		2,416,208
Asset retirement obligations		83,576		81,290
Derivative liabilities		47,745		29,687
Deferred taxes		1,589,912		1,547,992
Other liabilities		25,567		29,834
Total long-term liabilities		4,091,581		4,105,011
Commitments and contingencies (Note 7)				
Stockholders equity				
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding		-		-
Common stock, $.001 par value, 600,000,000 shares authorized; 402,155,781 and 400,291,033 shares issued, respectively		402		400

Paid-in capital in excess of par		3,061,793		3,045,937
Retained earnings		1,321,952		1,336,142
Accumulated other comprehensive income (loss)		3,692		(488)
Treasury stock, at cost, 298,707 and 78,524 shares, respectively		(6,474)		(1,284)
Total stockholders equity		4,381,365		4,380,707
Total liabilities and stockholders equity	$	9,111,419	$	9,065,063

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31,	
	2011	**2010**
Revenues and other income		
Oil, natural gas, and related product sales	$ 506,192	$ 330,886
CO_2 sales and transportation fees	4,924	4,497
Gain on sale of interests in Genesis	-	101,568
Interest income and other income	3,049	1,870
Total revenues and other income	514,165	438,821
Expenses		
Lease operating expenses	127,097	96,220
Production taxes and marketing expenses	32,751	19,317
CO_2 discovery and operating expenses	2,154	1,368
General and administrative	43,846	32,709
Interest, net of amounts capitalized of $10,957 and $21,312, respectively	48,777	26,416
Depletion, depreciation, and amortization	93,594	81,872
Derivatives expense (income)	170,750	(41,225)
Loss on early extinguishment of debt	15,783	-
Transaction and other costs related to the Encore Merger	2,359	44,999
Total expenses	537,111	261,676
Income (loss) before income taxes	(22,946)	177,145

Income tax provision (benefit)				
Current income taxes		(848)		669
Deferred income taxes		(7,908)		76,272
Consolidated net income (loss)		(14,190)		100,204
Less: net income attributable to noncontrolling interest		-		(3,316)
Net income (loss) attributable to Denbury stockholders	$	(14,190)	$	96,888
Net income (loss) per common share				
Basic	$	(0.04)	$	0.33
Diluted	$	(0.04)	$	0.32
Weighted average common shares outstanding				
Basic		397,386		294,143
Diluted		397,386		299,224

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,	
	2011	**2010**
Cash flows from operating activities		
Consolidated net income (loss)	$ (14,190)	$ 100,204
Adjustments needed to reconcile to net cash provided by operating activities		
Depletion, depreciation, and amortization	93,594	81,872
Deferred income taxes	(7,908)	76,272
Gain on sale of interests in Genesis	-	(101,568)
Stock-based compensation	10,201	7,806
Non-cash fair value derivative adjustments	172,338	(101,026)
Loss on early extinguishment of debt	15,783	-
Other, net	1,399	2,410
Changes in operating assets and liabilities:		
Accrued production receivable	(44,243)	(12,125)
Trade and other receivables	(20,160)	30,854
Other assets	(5,773)	(2,775)
Accounts payable and accrued liabilities	(90,382)	21,971
Oil and natural gas production payable	18,770	13,394
Other liabilities	(4,597)	(4,121)
Net cash provided by operating activities	124,832	113,168

Cash flows used for investing activities		
Oil and natural gas capital expenditures	(190,296)	(92,647)
Acquisitions of oil and natural gas properties	(29,801)	(340)
Cash paid in Encore Merger, net of cash acquired	-	(801,489)
CO_2 and other non-hydrocarbon gases - capital expenditures, including pipelines	(66,157)	(72,647)
Deposit received on divesture of Southern Assets	-	45,000
Net proceeds from sale of interests in Genesis	-	162,622
Other	1,211	(4,826)
Net cash used for investing activities	(285,043)	(764,327)
Cash flows from financing activities		
Bank repayments	(130,000)	(625,000)
Bank borrowings	130,000	1,025,000
Repayment of senior subordinated notes	(469,552)	(508,182)
Premium paid on repayment of senior subordinated notes	(13,137)	(6,257)
Net proceeds from issuance of senior subordinated notes	400,000	1,000,000
Escrowed funds for redemption of senior subordinated notes	-	(65,566)
Costs of debt financing	(8,441)	(76,129)
Other	(2,671)	(4,113)
Net cash provided by (used for) financing activities	(93,801)	739,753
Net increase (decrease) in cash and cash equivalents	(254,012)	88,594
Cash and cash equivalents at beginning of period	381,869	20,591
Cash and cash equivalents at end of period	$ 127,857	$ 109,185

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,	
	2011	**2010**
Consolidated net income (loss)	$ (14,190)	$ 100,204
Other comprehensive income (loss), net of income tax:		
Net unrealized gains 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 in each period	17	17
Change in deferred hedge loss on interest rate swaps, net of tax of $10	-	(27)
Consolidated comprehensive income (loss)	(10,010)	100,194
Less: comprehensive income attributable to noncontrolling interest	-	(3,285)
Comprehensive income (loss) attributable to Denbury stockholders	$ (10,010)	$ 96,909

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

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

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission (SEC) and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2010. Unless indicated otherwise or the context requires, the terms we, our, us, or Denbury, refer to Denbury Resources 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, 2011, our consolidated results of operations for the three months ended March 31, 2011 and 2010, and our consolidated cash flows for the three months ended March 31, 2011 and 2010. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter.

Noncontrolling Interest

From March 9, 2010 through December 31, 2010, we owned approximately 46% of Encore Energy Partners LP (ENP) outstanding common units and 100% of Encore Energy Partners GP LLC (GP LLC), which was ENP s general partner. Considering the presumption of control of GP LLC in accordance with the *Consolidation* topic of the Financial Accounting Standards Board Codification (FASC), the results of operations and cash flows of ENP were consolidated with those of Denbury for this period. On December 31, 2010 we sold all of our ownership interests in ENP and, therefore, we have not consolidated ENP in our Unaudited Condensed Consolidated Balance Sheets as of December 31, 2010, nor do our Unaudited Condensed Consolidated Statement of Operations or Cash Flows for the three months ended March 31, 2011 include ENP s results of operations or cash flows. As presented in the Unaudited Condensed Consolidated Statement of Operations for the three months ended March 31, 2010, Net income attributable to noncontrolling interest of $3.3 million represents ENP s results of operations attributable to third-party ENP limited partner interest owners, other than Denbury, for the portion of that period for which we consolidated ENP.

Net Income Per Common Share

Basic net income per common share is computed by dividing net income attributable to our stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact of the potential dilution from stock options, stock appreciation rights (SARs), unvested restricted stock, and unvested performance equity awards. For the three months ended March 31, 2011 and 2010, there were no adjustments to net income attributable to our stockholders for purposes of calculating diluted net income per common share. The following is a reconciliation of the weighted average common shares used in the basic and diluted net income per common share calculations for the periods indicated:

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

	Three Months Ended March 31,	
In thousands	2011	2010
Basic weighted average common shares	397,386	294,143
Potentially dilutive securities:		
Stock options and SARs	-	3,690
Performance equity awards	-	477
Restricted stock	-	914
Diluted weighted average common shares	397,386	299,224

Basic weighted average common shares excludes 3.5 million shares and 3.4 million shares at March 31, 2011 and 2010, respectively, of unvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share, although all restricted stock is issued and outstanding upon grant. For purposes of calculating diluted weighted average common shares, unvested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

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

	Three Months Ended March 31,	
In thousands	2011	2010
Stock options and SARs	12,641	5,465
Restricted stock	3,453	1,371

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 March 31, 2011 and December 31, 2010, short-term investments consisted entirely of our investment in Vanguard Natural Resources LLC (Vanguard) common units obtained as partial consideration for the sale of our interests in ENP to a subsidiary of Vanguard on December 31, 2010. The cost basis of this investment is $93.0 million, and under the terms of the sale agreement with Vanguard we are restricted from divesting these Vanguard common units until July 31, 2011. In the first quarter of 2011 we received distributions of $1.8 million on the Vanguard common units we own which distributions are included in Interest income and other income on our Unaudited Condensed Consolidated Statement of Operations for the three months ended March 31, 2011. The unrealized gain on our short-term investment of $4.2 million, net of taxes of $2.6 million, is included in our Unaudited Condensed Consolidated Statement of Comprehensive Operations for the three months ended March 31, 2011.

Recently Adopted Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the three months ended March 31, 2011, and have determined that none would have a material impact to our Unaudited Condensed

Consolidated Financial Statements.

Note 2. Acquisitions and Divestitures

2010 Merger with Encore Acquisition Company

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

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

For the period from the March 9, 2010 Encore acquisition date to March 31, 2010, we recognized $59.7 million and $43.9 million of oil, natural gas and related product sales and field operating income (oil, natural gas and related product sales less lease operating expenses and production taxes and marketing expenses), respectively, related to the Encore Merger. We recognized a total of $2.4 million and $45.0 million of transaction and other costs related to the Encore Merger (primarily advisory, legal, accounting, due diligence, integration, and severance costs) for the three months ended March 31, 2011, and 2010, respectively.

2010 Acquisition of Reserves in Rocky Mountain Region at Riley Ridge

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

The acquisition of Riley Ridge meets the definition of a business under the FASC *Business Combinations* topic. The purchase price allocation for the acquisition of interests in Riley Ridge Field is preliminary and subject to revision pending finalization of closing adjustments. The following table presents a summary of the preliminary fair value of assets acquired:

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

Pro Forma Information

Had the Encore Merger and Riley Ridge acquisition both occurred on January 1, 2010, our combined pro forma revenue and net income for the three months ended March 31, 2010, would have been as follows:

In thousands, except per share amounts		
Pro forma total revenues	$	615,271
Pro forma net income attributable to Denbury stockholders		112,489
Pro forma net income per common share:		
Basic	$	0.28
Diluted		0.28

2010 Sale of Interests in Genesis

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

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 3. Long-Term Debt

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

In thousands	March 31, 2011	December 31, 2010
Bank Credit Agreement	$ -	$ -
7 1/2% Senior Subordinated Notes due 2013, including discount of $96 and $437, respectively [(1)]	55,352	224,563
7 1/2% Senior Subordinated Notes due 2015, including premium of $427	-	300,427
9 1/2% Senior Subordinated Notes due 2016, including premium of $13,906 and $14,589, respectively	238,826	239,509
9 3/4% Senior Subordinated Notes due 2016, including discount of $21,067 and $22,139, respectively	405,283	404,211
8 1/4% Senior Subordinated Notes due 2020	996,273	996,273
6 3/8% Senior Subordinated Notes due 2021	400,000	-
Other Subordinated Notes, including premium of $39 and $41, respectively	3,845	3,848
NEJD financing	166,452	167,331
Free State financing	80,979	81,188
Capital lease obligations	6,217	6,806
Total	2,353,227	2,424,156
Less current obligations	8,446	7,948
Long-term debt and capital lease obligations	$ 2,344,781	$ 2,416,208

(1) These notes were repurchased on April 1, 2011.

Bank Credit Agreement

On March 9, 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and 23 other lenders as party thereto (the Bank Credit Agreement) with a maturity date of March 2014. Availability under the Bank Credit Agreement is subject to a borrowing base (currently $1.6 billion) which is re-determined semi-annually on or prior to May 1 and November 1 and upon requested special redeterminations. We expect our semi-annual redetermination to be finalized in mid-May 2011. We currently do not anticipate any reduction in our borrowing base as a result of this redetermination.

The borrowing base is adjusted at the banks discretion and is based in part upon external factors over which we have no control. If the borrowing base were to be less than outstanding borrowings under the Bank Credit Agreement, we would be required to repay the deficit over a period of four months. We incur a commitment fee of 0.5% on the unused portion of the credit facility or if less, the borrowing base. Loans under the Bank Credit Agreement mature in March 2014. We had no borrowings outstanding on the Bank Credit Agreement as of March 31, 2011.

6^{3}/8% Senior Subordinated Notes due 2021

In February 2011, we issued $400 million of 6$^{3}/_{8}$% 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 approximately $393 million were used to repurchase a portion of our outstanding 2013 Notes and 2015 Notes (see *Redemption of our 2013 and 2015 Notes* below).

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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

Redemption of our 2013 and 2015 Notes

On February 3, 2011, we commenced cash tender offers to purchase $225 million principal amount of our 2013 Notes and $300 million principal amount of our 2015 Notes. By March 3, 2011, upon expiration of the tender offers, 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 for 104.125% of par. We called the remaining 2013 and 2015 Notes, repurchasing all of the remaining outstanding 2015 Notes ($79.1 million) at 103.75% of par on March 21, 2011 and repurchasing all of the remaining outstanding 2013 Notes ($55.4 million) at par on April 1, 2011. During the first quarter of 2011, we recognized a $15.8 million loss associated with the first quarter of 2011 debt repurchases, which is included in our income statement under the caption Loss on early extinguishment of debt .

Note 4. Derivative Instruments and Hedging Activities

Oil and Natural Gas Derivative Contracts

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

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production for a period generally ranging from approximately 12 to 18 months in advance, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current worldwide economic uncertainties.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification. All of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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

	Three Months Ended March 31,	
In thousands	2011	2010
Oil		
Payment on settlements of derivative contracts	$ 5,028	$ 63,550
Fair value adjustments to derivative contracts - expense (income)	167,064	(61,821)
Total derivative expense - oil	172,092	1,729
Natural Gas		
Receipt on settlements of derivative contracts	(6,616)	(3,749)
Fair value adjustments to derivative contracts - expense (income)	5,274	(39,018)
Total derivative income - natural gas	(1,342)	(42,767)
Ineffectiveness on interest rate swaps	-	(187)
Derivative expense (income)	$ 170,750	$ (41,225)

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Fair Value of Commodity Derivative Contracts Not Classified as Hedging Instruments

The following tables present the fair value of our commodity derivative contracts:

				NYMEX Contract Prices Per Bbl			Estimated Fair Value Asset (Liability)	
		Type of		Weighted Average Price			March 31,	December 31,
Year	Months	Contract	Bbls/d	Swap	Floor	Ceiling	2011	2010
							(In thousands)	
Oil Contracts:								
2011	Jan - Mar	Swap	625	$ 79.18	$ -	$ -	$ -	$ (737)
		Collar	43,500	-	67.25	95.80	-	(3,656)
		Put	6,625	-	69.53	-	-	79
	Total Jan - Mar 2011		50,750				-	(4,314)
	Apr - June	Swap	625	79.18	-	-	(1,593)	(827)
		Collar	43,500	-	70.34	100.20	(34,918)	(12,113)
		Put	6,625	-	69.53	-	16	499
	Total Apr - June 2011		50,750				(36,495)	(12,441)
	July - Sept	Swap	625	79.18	-	-	(1,656)	(865)
		Collar	42,500	-	70.35	100.09	(48,434)	(17,308)
		Put	6,625	-	69.53	-	170	1,026
	Total July - Sept 2011		49,750				(49,920)	(17,147)
	Oct - Dec	Swap	625	79.18	-	-	(1,658)	(871)
		Collar	45,500	-	70.33	101.74	(53,941)	(18,878)
		Put	6,625	-	69.53	-	477	1,445
	Total Oct - Dec 2011		52,750				(55,122)	(18,304)
2012	Jan - Mar	Swap	625	81.04	-	-	(1,502)	(741)
		Collar	52,000	-	70.00	106.86	(55,070)	(19,065)
		Put	625	-	65.00	-	51	123

Total Jan - Mar 2012		53,250				(56,521)		(19,683)
Apr-June	Swap	625	81.04	-	-	(1,450)		(726)
	Collar	53,000	-	70.00	119.44	(29,230)		(3,288)
	Put	625	-	65.00	-	78		151
Total Apr - June 2012		54,250				(30,602)		(3,863)
July-Sept	Swap	625	81.04	-	-	(1,402)		(719)
	Collar	48,000	-	80.00	127.70	(6,663)		-
	Put	625	-	65.00	-	103		178
Total July - Sept 2012		49,250				(7,962)		(541)
Oct - Dec	Swap	625	81.04	-	-	(1,356)		(709)
	Collar	48,000	-	80.00	127.70	(6,014)		-
	Put	625	-	65.00	-	117		191
Total Oct - Dec 2012		49,250				(7,253)		(518)
					Total Oil Contracts	$ (243,875)	$	(76,811)

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

				Contract Prices Per MMBtu			Estimated Fair Value Asset (Liability)	
		Type of		Weighted Average Price			March 31,	December 31,
Year	Months	Contract	MMBtu/d	Swap	Floor	Ceiling	2011	2010
							(In thousands)	
Natural Gas Contracts:								
2011	Jan - Mar	Swap	33,500	$ 6.27	$ -	$ -	$ -	$ 5,846
	Total Jan-Mar 2011		33,500				-	5,846
	Apr-Jun	Swap	33,500	6.27	-	-	5,841	5,637
	Total Apr-June 2011		33,500				5,841	5,637
	July - Sept	Swap	33,500	6.27	-	-	5,327	5,300
	Total July-Sept 2011		33,500				5,327	5,300
	Oct - Dec	Swap	33,500	6.27	-	-	4,615	4,409
	Total Oct - Dec 2011		33,500				4,615	4,409
2012	Jan - Dec	Swap	20,000	6.53	-	-	11,753	11,618
	Total Jan - Dec 2012		20,000				11,753	11,618
				Total Natural Gas Contracts			27,536	32,810
				Total Commodity Derivative Contracts			$ (216,339)	$ (44,001)

As of March 31, 2011 and December 31, 2010, we had $21.2 million and $26.7 million, respectively, of deferred premiums payable, which relate to various oil and natural gas floor contracts and are payable on a monthly basis from

April 2011 to January 2013. These premiums are excluded from the above tables.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Additional Disclosures about Derivative Instruments

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

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) March 31, 2011	December 31, 2010
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative asset:			
Oil contracts	Derivative assets - current	$ 714	$ 3,050
Natural gas contracts	Derivative assets - current	18,631	21,192
Oil contracts	Derivative assets - long-term	298	1,301
Natural gas contracts	Derivative assets - long-term	8,905	11,618
Derivative liability:			
Oil contracts	Derivative liabilities - current	(198,772)	(55,256)
Deferred premiums	Derivative liabilities - current	(19,569)	(22,928)
Oil contracts	Derivative liabilities - long-term	(46,115)	(25,906)
Deferred premiums	Derivative liabilities - long-term	(1,630)	(3,781)
Total derivatives not designated as hedging instruments		$ (237,538)	$ (70,710)

Note 5. Fair Value Measurements

Fair Value Hierarchy

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

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

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

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. Instruments in this category include non-exchange-traded natural gas derivatives swaps that are based on regional pricing other than NYMEX (i.e., Houston Ship Channel).

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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, 2011				
Assets:				
Short-term investments	$ 99,733	$ -	$ -	$ 99,733
Oil and natural gas derivative contracts	-	13,202	15,346	28,548
Liabilities:				
Oil and natural gas derivative contracts	-	(244,887)	-	(244,887)
Total	$ 99,733	$ (231,685)	$ 15,346	$ (116,606)
December 31, 2010				
Assets:				
Short-term investments	$ 93,020	$ -	$ -	$ 93,020
Oil derivative contracts	-	20,683	16,478	37,161
Liabilities:				
Oil and natural gas derivative contracts	-	(81,162)	-	(81,162)
Total	$ 93,020	$ (60,479)	$ 16,478	$ 49,019

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the three months ended March 31, 2011 and 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Three Months Ended	Three Months Ended
In thousands	March 31, 2011	March 31, 2010
Balance, beginning of period	$ 16,478	$ -
Unrealized gains on commodity derivative contracts included in earnings	310	14,773
Commodity derivative contracts acquired from Encore	-	38,093
Receipts on settlement of commodity derivative contracts	(1,442)	(2,348)
Balance, end of period	$ 15,346	$ 50,518

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 (income) in the accompanying Unaudited Condensed Consolidated Statements of Operations.

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

	March 31, 2011		December 31, 2010	
In thousands, except percentages	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
7 1/2% Senior Subordinated Notes due 2013 [(1)]	$ 55,352	$ 55,448	$ 224,563	$ 228,375
7 1/2% Senior Subordinated Notes due 2015	-	-	300,427	310,500
9 1/2% Senior Subordinated Notes due 2016	238,826	253,597	239,509	249,661
9 3/4% Senior Subordinated Notes due 2016	405,283	480,710	404,211	475,380
8 1/4% Senior Subordinated Notes due 2020	996,273	1,113,335	996,273	1,080,956
6 3/8% Senior Subordinated Notes due 2021	400,000	410,000	-	-

(1) These notes were repurchased on April 1, 2011.

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

Note 6. Supplemental Information

Accounts Payable and Accrued Liabilities

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

In thousands	March 31, 2011	December 31, 2010
Accounts payable	$ 53,754	$ 47,660
Accrued exploration and development costs	75,967	101,758
Accrued compensation	17,820	39,757
Accrued interest	31,405	57,077
Taxes payable	7,198	34,371
Other	60,001	65,375
Total	$ 246,145	$ 345,998

Supplemental Cash Flow Information

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

	As of March 31,	
In thousands	2011	2010
Cash paid for interest, net of amounts capitalized	$ 66,172	$ 21,962
Interest capitalized	10,957	21,312
Cash paid for income taxes	19,933	8,030
Cash received for income tax refunds	222	12,625
Increase (decrease) in accrued liabilities for capital expenditures	(12,503)	32,399
Issuance of Denbury common stock in connection with the Encore Merger	-	2,085,681

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 7. Commitments and Contingencies

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

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

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

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.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 8. Condensed Consolidating Financial Information

Denbury s subordinated debt is fully and unconditionally guaranteed jointly and severally by certain of its subsidiaries, except that with respect to Denbury s $55 million of 7½% Senior Subordinated Notes due 2013 that remained outstanding at March 31, 2011, Denbury Resources Inc. and Denbury Onshore, LLC were co-obligors at March 31, 2011. These 7½% Notes have since been redeemed and are no longer outstanding. Except as noted in the first sentence of this paragraph, Denbury Resources Inc. is the sole issuer and Denbury Onshore, LLC is a subsidiary guarantor. In the case of the 6¼% Notes, the 6% Notes, the 7¼% Notes and the 9½% Notes previously issued by Encore, Denbury is the sole issuer by virtue of the fact that it is the successor in interest to Encore with respect to all such notes. Each subsidiary guarantor and the subsidiary that was a co-obligor are wholly-owned, directly or indirectly, by Denbury Resources Inc.

All intercompany investments in, loans due to/from, subsidiary equity, revenues, and expenses between Denbury Resources Inc., Denbury Onshore, LLC, guarantor subsidiaries, and non-guarantor subsidiaries are shown prior to consolidation with Denbury Resources Inc. and then eliminated to arrive at consolidated totals per the accompanying Unaudited Condensed Consolidated Financial Statements.

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DENBURY RESOURCES INC.
Notes to Unaudited Condensed Consolidated Financial Statements
Condensed Consolidating Balance Sheets

	March 31, 2011					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS						
Current assets:						
Cash and cash equivalents	$ 3,947	$ 119,569	$ 3,630	$ 711	$ -	$ 127,857
Other current assets	476,986	559,354	461,605	-	(904,139)	593,806
Total current assets	480,933	678,923	465,235	711	(904,139)	721,663
Property and equipment:						
Oil and natural gas properties (using full cost accounting):						-
Proved	-	6,238,629	-	-	-	6,238,629
Unevaluated	-	912,267	-	-	-	912,267
CO_2 and other non-hydrocarbon gases - properties and pipelines	-	707,008	1,223,900	9,484	-	1,940,392
Other property and equipment	-	128,421	4,271	-	-	132,692
Less accumulated depletion, depreciation, amortization, and impairment	-	(2,267,862)	(28,090)	-	-	(2,295,952)
Net property and equipment	-	5,718,463	1,200,081	9,484	-	6,928,028
Derivative assets	-	9,203	-	-	-	9,203
Goodwill	1,061,123	171,295	-	-	-	1,232,418
Other assets	549,334	144,456	7	33	(473,723)	220,107
Investment in subsidiaries (equity	4,354,965	2,666	4,369,801	-	(8,727,432)	-

method)						
Total assets	$ 6,446,355	$ 6,725,006	$ 6,035,124	$ 10,228	$ (10,105,294)	$ 9,111,419
LIABILITIES AND EQUITY						
Current liabilities	$ 20,764	$ 901,331	$ 609,794	$ 10,723	$ (904,139)	$ 638,473
Long-term debt, net of current portion	2,044,226	726,905	-	-	(426,350)	2,344,781
Asset retirement obligations	-	83,576	-	-	-	83,576
Derivative liabilities	-	47,745	-	-	-	47,745
Deferred taxes	-	569,597	1,067,688	-	(47,373)	1,589,912
Other liabilities	-	22,890	2,677	-	-	25,567
Total liabilities	2,064,990	2,352,044	1,680,159	10,723	(1,377,862)	4,730,054
Total equity	4,381,365	4,372,962	4,354,965	(495)	(8,727,432)	4,381,365
Total liabilities and equity	$ 6,446,355	$ 6,725,006	$ 6,035,124	$ 10,228	$ (10,105,294)	$ 9,111,419

	December 31, 2010					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS						
Current assets:						
Cash and cash equivalents	$ 457	$ 380,273	$ 1,139	$ -	$ -	$ 381,869
Other current assets	144,247	487,942	449,871	-	(599,611)	482,449
Total current assets	144,704	868,215	451,010	-	(599,611)	864,318
Property and equipment:						
Oil and natural gas properties (using full cost accounting):						-
Proved	-	6,042,442	-	-	-	6,042,442
Unevaluated	-	870,130	-	-	-	870,130
CO_2 and other non-hydrocarbon gases - properties and pipelines	-	681,963	1,216,841	2,858	-	1,901,662

Other property and equipment	-	116,370	4,271	-	-	120,641
Less accumulated depletion, depreciation, amortization and impairment	-	(2,177,040)	(20,477)	-	-	(2,197,517)
Net property and equipment	-	5,533,865	1,200,635	2,858	-	6,737,358
Derivative assets	-	12,919	-	-	-	12,919
Goodwill	1,061,123	171,295	-	-	-	1,232,418
Other assets	830,454	144,333	7	-	(756,744)	218,050
Investment in subsidiaries (equity method)	4,332,347	2,666	4,357,128	-	(8,692,141)	-
Total assets	$ 6,368,628	$ 6,733,293	$ 6,008,780	$ 2,858	$ (10,048,496)	$ 9,065,063
LIABILITIES AND EQUITY						
Current liabilities	$ 43,654	517,686	614,388	3,228	(599,611)	579,345
Long-term debt, net of current portion	1,944,267	1,198,291	-	-	(726,350)	2,416,208
Asset retirement obligations	-	81,290	-	-	-	81,290
Derivative liabilities	-	29,687	-	-	-	29,687
Deferred taxes	-	516,319	1,062,045	22	(30,394)	1,547,992
Other liabilities	-	29,834	-	-	-	29,834
Total liabilities	1,987,921	2,373,107	1,676,433	3,250	(1,356,355)	4,684,356
Total equity	4,380,707	4,360,186	4,332,347	(392)	(8,692,141)	4,380,707
Total liabilities and equity	$ 6,368,628	$ 6,733,293	$ 6,008,780	$ 2,858	$ (10,048,496)	$ 9,065,063

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations

	Three Months Ended March 31, 2011					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues and other income:						
Oil, natural gas, and related product sales	$ -	$ 506,192	$ -	$ -	$ -	$ 506,192
CO_2 sales and transportation fees	-	3,733	22,217	-	(21,026)	4,924
Interest income and other	32,433	3,047	8,594	-	(41,025)	3,049
Total revenues	32,433	512,972	30,811	-	(62,051)	514,165
Expenses:						
Lease operating expenses	-	145,846	-	-	(18,749)	127,097
Production taxes and marketing expenses	-	32,751	-	-	-	32,751
CO_2 discovery and operating expenses	-	1,809	2,622	-	(2,277)	2,154
General and administrative	191	42,553	945	157	-	43,846
Interest, net of amounts capitalized	50,321	12,647	(301)	-	(13,890)	48,777
Depletion, depreciation, and amortization	-	92,212	1,382	-	-	93,594
Derivatives expense	-	170,750	-	-	-	170,750
Loaa on early extinguishment of debt	13,670	2,113	-	-	-	15,783
Transaction costs and other related to the Encore Merger	-	123	2,236	-	-	2,359
Total expenses	64,182	500,804	6,884	157	(34,916)	537,111
Income (loss) before income taxes	(31,749)	12,168	23,927	(157)	(27,135)	(22,946)
Income tax provision (benefit)	(17,661)	3,574	5,386	(55)	-	(8,756)
	$ (14,088)	$ 8,594	$ 18,541	$ (102)	$ (27,135)	$ (14,190)

Consolidated net income (loss)

	Three Months Ended March 31, 2010					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Revenues and other income:						
Oil, natural gas, and related product sales	$ -	$ 270,571	$ 47,881	$ 12,434	$ -	$ 330,886
CO_2 sales and transportation fees	-	4,497	-	-	-	4,497
Gain on sale of interests in Genesis	-	(160)	101,728		-	101,568
Interest income and other	127,106	827	(7,446)	4	(118,621)	1,870
Total revenues	127,106	275,735	142,163	12,438	(118,621)	438,821
Expenses:						
Lease operating expenses	-	85,884	7,552	2,784	-	96,220
Production taxes and marketing expenses	-	12,277	5,653	1,387	-	19,317
CO_2 discovery and operating expenses	-	1,360	8	-	-	1,368
General and administrative	118	26,683	5,227	681	-	32,709
Interest, net of amounts capitalized	33,828	13,944	(6,418)	1,079	(16,017)	26,416
Depletion, depreciation, and amortization	-	65,025	13,748	3,099	-	81,872
Derivatives income	-	(31,638)	(5,817)	(3,770)	-	(41,225)
Transaction costs and other related to the Encore Merger		43,809	252	938	-	44,999
Total expenses	33,946	217,344	20,205	6,198	(16,017)	261,676
Income before income taxes	93,160	58,391	121,958	6,240	(102,604)	177,145
Income tax provision (benefit)	(7,044)	66,871	17,101	13	-	76,941
Consolidated net income (loss)	100,204	(8,480)	104,857	6,227	(102,604)	100,204

Less: net income attributable to noncontrolling interest		-		-		-		(3,316)		-		(3,316)
Consolidated net income (loss) attributable to Denbury stockholders	$	100,204	$	(8,480)	$	104,857	$	2,911	$	(102,604)	$	96,888

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DENBURY RESOURCES INC.
Notes to Unaudited Condensed Consolidated Financial Statements
Condensed Consolidating Statements of Cash Flows

	Three Months Ended March 31, 2011					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flow from operating activities:						
Net cash provided by (used for) operating activities	$ (74,995)	$ 476,567	$ 30,785	$ 5,549	$ (313,074)	$ 124,832
Cash flow used for investing activities:						
Oil and natural gas capital expenditures	-	(190,296)	-	-	-	(190,296)
Acquisitions of oil and natural gas properties	-	(29,801)	-	-	-	(29,801)
CO_2 and other non-hydrocarbon gases - capital expenditures, including pipelines	-	(33,025)	(28,294)	(4,838)	-	(66,157)
Other	-	1,211	-	-	-	1,211
Net cash used for investing activities	-	(251,911)	(28,294)	(4,838)	-	(285,043)
Cash flow from financing activities:						
Bank repayments	(130,000)	-	-	-	-	(130,000)
Bank borrowings	130,000	-	-	-	-	130,000
Repayment of senior subordinated notes	(300,000)	(469,552)	-	-	300,000	(469,552)
Premium paid on repayment of senior subordinated notes	(12,078)	(13,137)	-	-	12,078	(13,137)
Net proceeds from issuance of senior subordinated debt	400,000	-	-	-	-	400,000
Costs of debt financing	(8,441)	-	-	-	-	(8,441)
Other	(996)	(2,671)	-	-	996	(2,671)
Net cash provided by (used for) financing activities	78,485	(485,360)	-	-	313,074	(93,801)

Net increase (decrease) in cash and cash equivalents	3,490	(260,704)	2,491	711	-	(254,012)
Cash and cash equivalents at beginning of period	457	380,273	1,139	-	-	381,869
Cash and cash equivalents at end of period	$ 3,947	$ 119,569	$ 3,630	$ 711	$ -	$ 127,857

	Three Months Ended March 31, 2010					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
Cash flow from operating activities:						
Net cash provided by operating activities	$ 3,173	$ 219,573	$ 190,852	$ 6,882	$ (307,312)	$ 113,168
Cash flow used for investing activities:						
Oil and natural gas capital expenditures	-	(70,061)	(22,262)	(324)	-	(92,647)
Acquisitions of oil and natural gas properties	-	(503)	455	(292)	-	(340)
Cash paid in Encore Merger, net of cash acquired	(830,310)	-	15,705	13,116	-	(801,489)
CO_2 and other non-hydrocarbon gases - capital expenditures, including pipelines	-	(37,011)	(35,636)	-	-	(72,647)
Deposit received on divesture of Southern Assets	45,000	-	-	-	-	45,000
Net proceeds from sales of oil and gas properties and equipment	-	23,537	139,085	-	-	162,622
Investments in subsidiaries (equity method)	(305,646)	-	-	-	305,646	-
Other	-	(4,799)	(27)	-	-	(4,826)
	(1,090,956)	(88,837)	97,320	12,500	305,646	(764,327)

Net cash provided by (used for) investing activities						
Cash flow from financing activities:						
Bank repayments	-	(350,000)	(265,000)	(10,000)	-	(625,000)
Bank borrowings	800,000	225,000	-	-	-	1,025,000
Repayment of senior subordinated notes	(508,182)	-	-	-	-	(508,182)
Premium paid on repayment of senior subordinated notes	(6,257)					(6,257)
Net proceeds from issuance of senior subordinated debt	1,000,000	-	-	-	-	1,000,000
Escrowed Funds for senior subordinated notes redemption	(65,566)	-	-	-	-	(65,566)
Costs of debt financing	(76,129)	-	-	-	-	(76,129)
Other	(1,666)	(2,139)	(1,974)	-	1,666	(4,113)
Net cash provided by (used for) financing activities	1,142,200	(127,139)	(266,974)	(10,000)	1,666	739,753
Net increase in cash and cash equivalents	54,417	3,597	21,198	9,382	-	88,594
Cash and cash equivalents at beginning of period	24	20,281	286	-	-	20,591
Cash and cash equivalents at end of period	$ 54,441	$ 23,878	$ 21,484	$ 9,382	$ -	$ 109,185

Note 9. Subsequent Events

Redemption of our 2013 Notes

On February 3, 2011, we commenced cash tender offers to purchase $225 million principal amount of our 2013 Notes. By March 3, 2011, upon expiration of the tender offers, we accepted for purchase $169.6 million in principal amount of the 2013 Notes at 100.625% of par. On April 1, 2011, we repurchased all $55.4 million of our 2013 Notes remaining outstanding at par in accordance with the terms of our indenture. See Note 3, *Long-Term Debt*, to the Unaudited Condensed Consolidated Financial Statements for more information.

DENBURY RESOURCES INC.

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

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2010, along with *Management s Discussion and Analysis of Financial Condition and Results of Operations* contained in such Form 10-K. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of this report, along with *Forward-Looking Information* at the end of this section for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

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

Operating Highlights. The acquisition of Encore Acquisition Company (the Encore Merger) on March 9, 2010, has had a significant impact on nearly every aspect of our business, including oil and natural gas production, revenues and operating expenses. Accordingly, the Encore Merger impacts the comparability of our first quarter 2010 financial results to those in the first quarter of 2011, which is more fully discussed throughout the following discussion and analysis. Our first quarter 2010 financial results include the results of operations for Encore from the date of the acquisition on March 9, 2010 through March 31, 2010. Additionally, throughout 2010 we disposed of non-strategic Encore properties and our ownership interests in Encore Energy Partners LP (ENP).

We recognized a net loss of $14.2 million, or $0.04 per basic common share, during the first quarter of 2011 as compared to net income of $96.9 million, or $0.33 per basic common share, during the first quarter of 2010. This decrease between the two periods is primarily attributable to (1) non-cash fair value losses for our commodity derivatives of $172.3 million in the first quarter of 2011 compared to gains of $100.8 million in 2010, resulting in a $273.1 million negative change between the comparable quarters ($169.3 million after tax), (2) a $101.6 million gain on the sale of Genesis in the first quarter of 2010 ($63.0 million after tax), and (3) a $15.8 million loss in the first quarter of 2011 associated with repurchases of senior subordinated notes ($9.8 million after tax). Partially offsetting these decreases was an increase in oil and gas revenues of $175.3 million due to increased volumes attributable to a full quarter of production from the properties retained from the Encore Merger (versus 22 days of production in the first quarter of 2010), increased tertiary production, and higher oil prices. In-line with higher production volumes, our operating expenses increased across the board. Interest expense also increased significantly due to our additional debt incurred in conjunction with the Encore Merger.

During the first quarter of 2011, our oil and natural gas production averaged 63,604 BOE/d compared to 53,125 BOE/d produced during the first quarter of 2010. This 10,479 BOE/d of additional production is primarily attributable to (1) incremental average production of 14,400 BOE/d from Rocky Mountain region properties acquired in the Encore Merger, and (2) increased tertiary production between the two quarters, offset by (3) a decrease of 6,750 BOE/d due to the sales of non-strategic Encore assets and our interests in ENP after the first quarter of 2010. See *Results of Operations Operating Results Production* for more information.

Tertiary oil production averaged 30,825 Bbls/d during the first quarter of 2011, representing a 14% increase over our average tertiary oil production of 27,023 Bbls/d during the first quarter of 2010. However, tertiary oil production was down slightly from the 31,139 Bbls/d produced during the fourth quarter of 2010. See *Results of Operations CO_2 Operations* for more information.

Oil prices during the first quarter of 2011 were considerably higher than prices during the first quarter of 2010. Our average oil and natural gas price received per BOE, excluding the impact of commodity derivative contracts, was $88.42 per BOE during the first quarter of 2011, compared to $69.21 per BOE during the first quarter of 2010, a 28%

increase between the two periods. Including the impact of cash settlements on our commodity derivative contracts, our average oil and natural gas price per BOE was $88.70 per BOE during the first quarter of 2011 compared to $56.70 per BOE during the first quarter of 2010.

DENBURY RESOURCES INC.

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

Debt Refinancing. In February 2011, we issued, at par, \$400 million of $6^3/_8$% Senior Subordinated Notes due 2021. The net proceeds, together with cash on hand, were used to repurchase \$525 million in principal amount of our outstanding 2013 Notes and 2015 Notes. Also, in February, we commenced cash tender offers to purchase \$225 million principal amount of our 2013 Notes and \$300 million principal amount of our 2015 Notes. Upon expiration of the tender offers in March 2011, we accepted for purchase \$169.6 million in principal of the 2013 Notes at 100.625% of par and \$220.9 million in principal of the 2015 Notes at 104.125% of par. We called the remaining 2013 and 2015 Notes, repurchased all of the remaining outstanding 2015 Notes at 103.75% of par on March 21, 2011 and repurchased all of the remaining outstanding 2013 Notes at par on April 1, 2011. During the first quarter of 2011, we recognized a \$15.8 million loss associated with the debt repurchases, included in our income statement under the caption Loss on early extinguishment of debt .

CO_2 Purchase Contracts. In March 2011, we entered into three long-term supply contracts to purchase CO_2 from future anthropogenic sources in the Gulf Coast and Rocky Mountain regions. Denbury will purchase 100% of the CO_2 captured from the DKRW Advanced Fuels LLC s Medicine Bow Fuel and Power LLC (MBFP) project in Medicine Bow, Wyoming, purchase 70% of the CO_2 captured from Mississippi Power Company s Kemper County Integrated Gasification Combined Cycle (IGCC) project in Mississippi, and purchase 100% of the CO_2 captured from an undisclosed source in the Gulf Coast region. We estimate that these sources will supply approximately 365 MMcf/d of CO_2 for our enhanced oil recovery operations, although under certain circumstances, we may be obligated to purchase up to 460 MMcf/d, a portion of which would be at a reduced price per Mcf. We expect to begin taking delivery of approximately 200 MMCF/d of CO_2 from the MBFP project in late 2014 or early 2015, 115 MMcf/d of CO_2 from the IGCC project by 2014, and 50 MMcf/d of CO_2 from a Gulf Coast region source in late 2012. Our aggregate maximum purchase obligation for CO_2 purchased under these three contracts would be approximately \$110 million per year (assuming purchases of 460 MMcf/d), plus transportation, assuming a \$100 per barrel NYMEX oil price. The purchase price of CO_2 will fluctuate based on the changes in the price of oil. These CO_2 purchase agreements are contingent on completion or modification of the respective plants by their operators.

Capital Resources and Liquidity

In March 2011, commensurate with higher oil prices, our Board of Directors approved an increase in our 2011 capital spending budget, from \$1.1 billion to \$1.3 billion, excluding capitalized interest, tertiary start-up costs, acquisitions and divestitures, and net of equipment leases. Our current 2011 capital budget includes the following:

- \$450 million allocated for tertiary oil field expenditures;
- \$350 million in the Bakken area of North Dakota;
- \$250 million to be spent on our CO_2 pipelines;
- \$150 million to be spent on CO_2 sources in the Jackson Dome and Riley Ridge areas; and
- \$100 million on drilling, completion and other development activities in our other areas.

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

Based on oil and natural gas commodity futures prices in early May 2011 and our current production forecasts, excluding acquisition costs, our 2011 capital budget, including capitalized interest and tertiary start-up costs, is \$100 million to \$200 million greater than our anticipated cash flow from operations. These expenditures will be funded with our excess cash on hand or, if necessary, borrowings under our \$1.6 billion Bank Credit Agreement which currently has no outstanding borrowings.

DENBURY RESOURCES INC.

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

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 2011, we have contracted for certain capital expenditures, including construction of the Greencore pipeline, processing facilities at Riley Ridge, and several drilling rigs, and 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 our Annual Report on Form 10-K for the year ended December 31, 2010 for further information regarding these commitments). See *CO_2 Purchase Contracts* above and *Off-Balance Sheet Arrangements* below for further information regarding additional commitments entered into in 2011. We believe that our $1.6 billion Bank Credit Agreement and oil derivative contracts, which provide a $70 floor price through mid-2012 and an $80 floor price for the second half of 2012 on approximately 80%-85% of our currently anticipated proved oil production, provide us with adequate liquidity and flexibility to meet our near-term capital spending plans if oil prices were to decrease significantly.

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

	Three Months Ended March 31,	
In thousands	2011	2010
Oil and natural gas exploration and development:		
Drilling	$ 91,732	$ 48,261
Geological, geophysical, and acreage	6,666	6,994
Facilities	51,814	37,710
Recompletions	47,402	28,536
Capitalized interest	7,700	5,743
Total oil and natural gas exploration and development expenditures	205,314	127,244
CO_2 and other non-hydrocarbon gases - capital expenditures:		
Pipelines and facilities	24,737	42,973
Acreage, geological and drilling	10,615	11,907
Capitalized interest	3,257	15,569
Total CO_2 and other non-hydrocarbon gases capital expenditures	38,609	70,449
Total capital expenditures excluding acquisitions	243,923	197,693
Oil and natural gas property acquisitions	29,801	340
Consideration for Encore Merger[1]	-	2,952,515
Total	$ 273,724	$ 3,150,548

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

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. Our capital expenditures for the first three months of 2010, excluding the Encore Merger, were funded with $113.2 million of cash flow from operations and proceeds from the sale of our interests in Genesis.

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.

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

In April 2011, we entered into three long-term drilling contracts. Our total commitment under these contracts is approximately $55.8 million, with $5.2 million expected to be paid in 2011, $18.6 million in both 2012 and 2013, and $13.4 million in 2014.

Please refer to *Management s Discussion and Analysis of Financial Condition and Results of Operations* and the section entitled *Off-Balance Sheet Arrangements Commitments and Obligations* contained in our Annual Report on Form 10-K for the year ended December 31, 2010 for further information regarding our commitments and obligations. Also see *Overview CO_2 Purchase Contracts* for discussion of additional purchase contracts we entered into during the first quarter of 2011.

Results of Operations

CO_2 Operations

Our focus on CO_2 operations is the primary strategy of our business and operations. We believe that there are significant additional oil reserves and production that can be obtained through the use of CO_2, and we have outlined certain of this potential in our Annual Report on Form 10-K for the year ended December 31, 2010 and other public disclosures. In addition to its long-term effect, our focus on these types of operations impacts certain trends in our current and near-term operating results. Please refer to *Management s Discussion and Analysis of Financial Condition and Results of Operations* and the section entitled *CO_2 Operations* contained in our Annual Report on Form 10-K for the year ended December 31, 2010 for further information regarding these matters.

During the first quarter of 2011, our CO_2 production at Jackson Dome averaged 1,021 MMcf/d as compared to an average of 802 MMcf/d produced during the first quarter of 2010 and 974 MMcf/d produced during the fourth quarter of 2010. We used 91% of this production, or 926 MMcf/d, in our tertiary operations during the first quarter of 2011, and sold the balance to our industrial customers, or to Genesis pursuant to our volumetric production payments. Refer to *Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Off-Balance Sheet Arrangements Commitments and Obligations* in our Annual Report on Form 10-K for the year ended December 31, 2010 for further discussion on our CO_2 delivery obligations.

We spent approximately $0.25 per Mcf in operating expenses to produce our CO_2 during the first three months of 2011, which is up significantly from our $0.20 per Mcf cost during the first three months of 2010, due primarily to increased CO_2 royalty expense as a result of higher oil prices (to which CO_2 royalties are tied).

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

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

Oil production from our tertiary operations increased to an average of 30,825 Bbls/d during the first quarter of 2011, a 14% increase over our first quarter of 2010 tertiary production level of 27,023 Bbls/d, primarily due to production growth in response to continued expansion of the tertiary floods in the Tinsley, Heidelberg and Delhi Fields. Offsetting these production gains were declines in our Mallalieu, Soso, and Eucutta Fields, production from which has most likely peaked and will likely continue to decline in the future.

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

With the Green Pipeline complete, we initiated CO_2 injections at Oyster Bayou and Hastings Fields during June 2010 and December 2010, respectively. We currently anticipate tertiary production responses at Hastings Field in late 2011 or early 2012, depending on the date of completion of our CO_2 recycle facilities at this field. We anticipate first production at Oyster Bayou Field late in the first quarter of 2012, also dependant on the completion of CO_2 recycle facilities. We received the regulatory approvals required to commence construction of the CO_2 recycling facilities at Hastings and Oyster Bayou Fields in the fourth quarter of 2010, after extensive unforeseen regulatory delays, and began construction of these facilities in the first quarter of 2011.

DENBURY RESOURCES INC.

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

During the first quarter of 2011, operating costs for our tertiary properties averaged $25.40 per Bbl, compared to our first quarter of 2010 average cost of $22.67 per Bbl and a fourth quarter of 2010 average of $22.26 per Bbl. The per Bbl increase quarter to quarter was primarily due to increases in utilities, CO_2 costs (which are variable and partially tied to oil prices), and workover expenses. On a per Bbl basis, our cost of CO_2 increased by $0.69 per Bbl, from $4.89 per Bbl during the first quarter of 2010 to $5.58 per Bbl during the first quarter of 2011 and increased $0.03 from $5.55 per Bbl during the fourth quarter of 2010 due to slightly lower CO_2 injection levels at our tertiary producing fields. First quarter of 2011 workover expenses increased $1.32 per Bbl over the first quarter of 2010 levels and $1.39 per Bbl over fourth quarter of 2010 levels as we accelerated planned mechanical integrity test repairs at Brookhaven Field rather than performing the work throughout the year as originally planned. For any specific field, we expect our tertiary lease operating expense per Bbl to be high initially and then decrease as production increases, ultimately leveling off until production begins to decline in the latter life of the field, when lease operating expense per Bbl will again increase.

Operating Results

Certain of our operating results and statistics for the first three months of 2011 and 2010 are included in the following table:

In thousands, except per share and unit data	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010 [(1)]
Operating results:		
Net income (loss) attributable to Denbury stockholders	$ (14,190)	$ 96,888
Net income (loss) per common share - basic	(0.04)	0.33
Net income (loss) per common share - diluted	(0.04)	0.32
Cash flow from operations	124,832	113,168
Average daily production volumes:		
Bbls/d	58,460	44,309
Mcf/d	30,866	52,892
BOE/d	63,604	53,125
Operating revenues:		
Oil sales	$ 492,838	$ 305,204
Natural gas sales	13,354	25,682
Total oil and natural gas sales	$ 506,192	$ 330,886
Commodity derivative contracts: [(2)]		
Net cash receipts (payments) on settlement of commodity derivative contracts	$ 1,588	$ (59,801)
Non-cash fair value adjustment income (expense)	(172,338)	100,839
Total income (expense) from commodity derivative contracts	$ (170,750)	$ 41,038
Operating expenses:		
Lease operating	$ 127,097	$ 96,220
Production taxes and marketing	32,751	19,317
Total production expenses	$ 159,848	$ 115,537

Unit prices - including impact of derivative settlements: [2]				
Oil price per Bbl	$	92.72	$	60.60
Natural gas price per Mcf		7.19		6.18
Unit prices - excluding impact of derivative settlements: [2]				
Oil price per Bbl	$	93.67	$	76.53
Natural gas price per Mcf		4.81		5.40
Oil and natural gas operating revenues and expenses per BOE:				
Oil and natural gas revenues	$	88.42	$	69.21
Oil and natural gas lease operating expenses	$	22.20	$	20.12
Oil and natural gas production taxes and marketing expense		5.72		4.04
Total oil and natural gas production expenses	$	27.92	$	24.16

(1) Includes the results of operations of Encore properties and ENP from March 9, 2010 through March 31, 2010.

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

DENBURY RESOURCES INC.

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

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

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

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

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

As outlined in the above table, continuing production during the three months ended March 31, 2011 increased 7% over first quarter 2010 pro forma production levels. These increases were primarily due to the additional production from a 14% increase in our tertiary production and a 61% increase in production from the Bakken, partially offset by normal declines in most of our other properties or declines resulting from a conversion of a portion of the field to a tertiary flood. Additionally, our production from the Cedar Creek Anticline generally declines in periods of increasing prices due to a net profits interest associated with this production.

Production from our Bakken properties averaged 5,728 BOE/d in the first quarter, a 61% increase from first quarter 2010 pro forma production levels and an increase of over 10% as compared to fourth quarter 2010 production levels. The production increases in the Bakken are due to a gradual acceleration of our drilling activities in the area, as we have increased our operated drilling rigs from two, at the time of the Encore acquisition in March 2010, to five operated rigs. We anticipate adding a sixth rig in the third quarter of 2011 to test our acreage in the Almond area, and will likely add a seventh rig by the end of 2011. Our first quarter 2011 Bakken production was negatively impacted by severe winter weather which caused delays in well completions.

DENBURY RESOURCES INC.

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Our production during the three months ended March 31, 2011 was 92% oil as compared to 83% during the three months ended March 31, 2010. This increase is due to the sales of the non-strategic Encore properties and ENP properties in the second half of 2010, which had a higher percentage of natural gas production.

Oil and Natural Gas Revenues. Due to the significant increase in oil prices between the first three months of 2010 and 2011, our oil and natural gas revenues increased sharply during the first quarter of 2011 as compared to revenues in the first quarter of 2010. These changes in oil and natural gas revenues, excluding any impact of our commodity derivative contracts, are reflected in the following table:

	Three Months Ended March 31, 2011 vs. 2010	
In thousands	Increase in Revenues	Percentage Increase in Revenues
Change in oil and natural gas revenues due to:		
Increase in commodity prices	$ 110,042	33%
Increase in production	65,264	20%
Total increase in oil and natural gas revenues	$ 175,306	53%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first three month period of 2011 and 2010:

	Three Months Ended March 31,	
	2011	2010
<u>Net Realized Prices:</u>		
Oil price per Bbl	$ 93.67	$ 76.53
Natural gas price per Mcf	4.81	5.40
Price per BOE	88.42	69.21
<u>NYMEX Differentials:</u>		
Oil per Bbl	$ (0.59)	$ (2.08)
Natural gas per Mcf	0.61	0.37

Our oil NYMEX differential improved during the three months ended March 31, 2011 as compared to our differential in the comparable period of 2010, primarily due to the favorable differential for crude oil sold under Light Louisiana Sweet (LLS) index prices, which are the sales prices for approximately 40% of our oil production. During the latter part of the first quarter, the LLS index price increased significantly more than increases in the NYMEX West Texas Intermediate crude oil price, trading as high as $20 over NYMEX. For the first quarter of 2011 this LLS-to-NYMEX differential averaged a positive $9.52 per barrel on a trade-month basis, as compared to a $4.07 differential in the fourth quarter of 2010 and a more typical $2.06 in the first quarter of 2010. While this differential is a significant portion of the pricing formula for approximately 40% of our oil production, other factors may prevent us from realizing the full differential. It is uncertain how long this LLS-to-NYMEX differential will remain at this level. Our oil price differential in the first quarter of 2010 was $2.08 per Bbl below NYMEX, which reflected only a partial period for the acquired Encore properties, which typically receive lower oil prices than our legacy production.

DENBURY RESOURCES INC.

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

Commodity Derivative Contracts. The following tables summarize the impact that our commodity derivative contracts had on our operating results for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31,					
	2011	2010	2011	2010	2011	2010
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value gain (loss)	$ (167,064)	$ 61,821	$ (5,274)	$ 39,018	$ (172,338)	$ 100,839
Cash settlement receipts (payments)	(5,028)	(63,550)	6,616	3,749	1,588	(59,801)
Total	$ (172,092)	$ (1,729)	$ 1,342	$ 42,767	$ (170,750)	$ 41,038

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

Production Expenses. Our lease operating expenses increased approximately 32% between the three months ended March 31, 2011 and 2010 primarily as a result of:

the completion of the Encore Merger on March 9, 2010;

our increasing emphasis on tertiary operations and additional tertiary fields moving into the productive phase (see discussion of those expenses under *CO_2 Operations*);

higher CO_2 costs, primarily due to increasing oil prices (see discussion of those expenses under *CO_2 Operations*);

increasing personnel and related costs resulting primarily from the Encore Merger; and

increased workover costs primarily in our CO_2 operations (see discussion of those expenses under *CO_2 Operations*).

Lease operating expense per BOE averaged $22.20 per BOE for the three months ended March 31, 2011, as compared to $20.12 per BOE for the same period in 2010. Our tertiary operating costs, which have historically been higher than our company-wide operating costs, averaged $25.40 per BOE during the three months ended March 31, 2011, compared to $22.67 per BOE for the same period in 2010. See *CO_2 Operations* for a more detailed discussion.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes, and as such, increased 70% during the three months ended March 31, 2011, as compared to the same period in 2010. This compares to an increase in oil and natural gas revenues of 53% during the three months ended March 31, 2011. The addition of properties in other operating areas acquired in the Encore Merger also affected these costs. Transportation and plant processing fees increased approximately $1.4 million during the three months ended March 31, 2011 and 2010, primarily due to the addition of properties in other operating areas acquired in the Encore Merger.

General and Administrative Expenses

General and administrative (G&A) expenses increased on both a gross and per BOE basis between the three months ended March 31, 2011 and 2010 as set forth below:

In thousands, except per BOE data and employees	Three Months Ended March 31, 2011	2010
Gross cash G&A expense	$ 67,697	$ 48,274
Gross stock-based compensation	11,337	9,939
State franchise taxes	1,159	1,070
Operator labor and overhead recovery charges	(29,716)	(22,045)
Capitalized exploration and development costs	(6,631)	(4,529)
Net G&A expense	$ 43,846	$ 32,709
G&A per BOE:		
Net cash G&A expense	$ 5.86	$ 4.84
Net stock-based compensation	1.60	1.78
State franchise taxes	0.20	0.22
Net G&A expense	$ 7.66	$ 6.84
Employees as of March 31	1,182	1,251

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

Gross cash G&A expenses increased $19.4 million (40%) during the three months ended March 31, 2011, as compared to the same period of 2010, primarily due to the Encore Merger which closed March 9, 2010. The number of employees at March 31, 2011 compared to March 31, 2010 decreased by 6%, as many Encore employees who did not accept permanent positions with Denbury completed their pre-defined transition period in early 2011. However, compensation and personnel costs were less for the three months ended March 31, 2010, as the compensation and personnel costs for Encore employees were included in our G&A expenses beginning March 9, 2010, the date of the Encore Merger. Prior to the Encore Merger on March 9, 2010, our headcount was 856 employees. The largest increases were related to personnel costs, including salaries, payroll taxes and our 401(k) match. Wage increases also contributed to the increase in G&A, as we consider this necessary in order to remain competitive in our industry.

Additional expense attributable to the legacy Encore office leases and the new Denbury headquarters lease, together with related moving costs, contributed to the higher cash G&A expense during the first quarter of 2011. Additionally, stock-based compensation expense increased $1.4 million when compared to levels in the same period of 2010, due primarily to the effect of Encore s employees being included for a full quarter in 2011 versus only 22 days during the first quarter of 2010.

The increase in gross G&A expense during the three months ended March 31, 2011, as compared to those costs in the same period of 2010, was offset in part by an increase in operator overhead recovery charges. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells from acquisitions, additional tertiary operations, drilling activity during the past year, and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 35% during the three months ended March 31, 2011, as compared to the same period in 2010. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs.

The net effect of these changes resulted in a 34% increase (a 12% increase on a per BOE basis) in G&A expense between the comparable first quarters of 2011 and 2010.

Interest and Financing Expenses

In thousands, except per BOE data and interest rates	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Cash interest expense	$ 54,206	$ 44,974
Non-cash interest expense	5,528	2,754
Less: capitalized interest	(10,957)	(21,312)
Interest expense	$ 48,777	$ 26,416
Interest income and other	$ (3,049)	$ 1,870
Net cash interest expense and other income per BOE (1)	$ 7.10	$ 4.67
Average debt outstanding	$ 2,514,621	$ 2,225,700
Average interest rate (2)	8.3%	8.1%

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

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

Interest expense increased $22.4 million during the three months ended March 31, 2011, as compared to the same period in 2010, primarily due to the increase in our average debt outstanding to finance the Encore Merger which closed in March 2010, a portion of which was repaid during 2010 with proceeds from the sale of non-strategic legacy

Encore assets and our ENP ownership interest. The increase in interest expense between the comparative three month periods was also attributable to a 49% decrease in our capitalized interest relating primarily to the Green Pipeline, which was completed and placed into service during the second half of 2010.

DENBURY RESOURCES INC.

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

Depletion, Depreciation, and Amortization

In thousands, except per BOE data	Three Months Ended March 31, 2011	2010
Depletion, depreciation, and amortization (DD&A) of oil and natural gas properties	$ 82,086	$ 71,197
Depletion and depreciation of CO_2 assets	4,590	5,300
Asset retirement obligations	1,563	1,107
Depreciation of other fixed assets	5,355	4,268
Total DD&A	$ 93,594	$ 81,872
DD&A per BOE:		
Oil and natural gas properties	$ 14.61	$ 15.12
CO_2 assets and other fixed assets	1.74	2.00
Total DD&A cost per BOE	$ 16.35	$ 17.12

Depletion of oil and natural gas properties increased on an absolute dollars basis during the three months ended March 31, 2011 as compared to the same period of 2010, primarily due to the Encore Merger. However, on a per BOE basis, our DD&A expense decreased from quarter-to-quarter due to incremental production attributable to the properties acquired from Encore, the acquisition of Riley Ridge, and higher tertiary production in the first quarter of 2011.

We continually evaluate the performance of our tertiary projects, and if performance indicates that we are reasonably certain of recovering additional reserves from these floods, we recognize those incremental reserves in that quarter. Since we adjust our DD&A rate each quarter based on any changes in our estimates of oil and natural gas reserves and costs, our DD&A rate could change significantly in the future.

Our DD&A expense for our CO_2 assets decreased on an absolute basis for the three months ended March 31, 2011 compared to the prior periods due to proved CO_2 reserve increases at Jackson Dome and Riley Ridge at the end of 2010. On a per BOE basis, DD&A expense for our CO_2 assets and other fixed assets decreased for the three months ended March 31, 2011 compared to those in the prior year quarter due to increased oil and natural gas production volumes as a result of the Encore Merger, which closed in March 2010, and as a result of proved CO_2 reserve additions noted above.

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, 2011. However, if oil and natural gas prices were to decrease significantly in subsequent periods, we may be required to record write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, and additional capital spent.

Encore Transaction and Other Costs

FASC *Business Combinations* topic requires that all transaction-related costs (advisory, legal, accounting, due diligence, integration, etc.) be expensed as incurred. We recognized transaction and other costs of $2.4 million and $45.0 million for the three months ended March 31, 2011 and 2010, respectively, associated with the Encore Merger, including $1.8 million and $1.2 million, respectively, related to severance costs. We anticipate that these severance costs will decline in the remainder of 2011 as the integration winds down and fewer former Encore transition employees remain.

DENBURY RESOURCES INC.

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

Income Taxes

	Three Months Ended March 31,	
In thousands, except per BOE amounts and tax rates	2011	2010
Current income tax provision (benefit)	$ (848)	$ 669
Deferred income tax provision (benefit)	(7,908)	76,272
Total income tax provision (benefit)	$ (8,756)	$ 76,941
Average income tax provision per BOE	$ (1.53)	$ 16.09
Effective tax rate	38.2%	43.4%

Our income taxes are based on an estimated statutory rate of approximately 38%. Our effective tax rate for the first quarter of 2011 was slightly higher compared to our statutory rate, primarily due to nondeductible compensation. Our effective tax rate for the comparative quarter was higher than the historical statutory rate due to the remeasurement of our deferred tax liabilities as a result of the Encore Merger in the first quarter of 2010 that resulted in an additional income tax provision of approximately $10 million. During the three months ended March 31, 2010, the current income tax expense represented our state income taxes, primarily related to the sale of our interest in Genesis.

As of March 31, 2011, we had an estimated $39.8 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.5 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2011 or future years. The enhanced oil recovery credits do not begin to expire until 2024. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

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

The current administration in Washington D.C. is attempting to remove many tax incentives for the oil and gas industry. Those items that would have the most significant impact on us would include the loss of the domestic manufacturing deduction as well as the repeal of the immediate expensing of intangible drilling costs and tertiary injectant costs. It is uncertain whether or not the current administration will be successful in changing the laws, but if they were successful, it would likely increase the amount of cash taxes that we pay. Should cash taxes increase significantly, it could impact our forecasted 2011 capital expenditure budget.

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

Per BOE Data

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

	Three Months Ended March 31,	
Per BOE data	2011	2010
Oil and natural gas revenues	$ 88.42	$ 69.21
Gain (loss) on settlements of derivative contracts	0.28	(12.51)
Lease operating expenses	(22.20)	(20.12)
Production taxes and marketing expenses	(5.72)	(4.04)
Production netback	60.78	32.54
Non-tertiary CO_2 operating margin	0.48	0.65
General and administrative expenses	(7.66)	(6.84)
Transaction and other costs related to the Encore Merger	(0.41)	(9.41)
Net cash interest expense and other income	(7.10)	(4.67)
Current income taxes and other	1.29	1.53
Changes in assets and liabilities relating to operations	(25.57)	9.87
Cash flow from operations	21.81	23.67
DD&A	(16.35)	(17.12)
Deferred income taxes	1.38	(15.95)
Gain on sale of interests in Genesis	-	21.24
Loss on early extinguishment of debt	(2.76)	-
Non-cash fair value derivative adjustments	(30.11)	21.13
Net income attributable to noncontrolling interest	-	(0.69)
Changes in assets and liabilities and other non-cash items	23.55	(12.02)
Net income (loss) attributable to Denbury stockholders	$ (2.48)	$ 20.26

Critical Accounting Policies

For additional discussion of our critical accounting policies, which remain unchanged, see *Management s Discussion and Analysis of Financial Condition and Results of Operations* in our Annual Report on Form 10-K for the year ended December 31, 2010.

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DENBURY RESOURCES INC.

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 this *Management s Discussion and Analysis of Financial Condition and Results of Operations,* are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, dates of pipeline construction commencement and completion, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, timing of CO_2 injections in tertiary flooding projects, cost savings, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves, potential reserves from tertiary operations, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and natural gas prices, liquidity, cash flows, availability of capital, borrowing capacity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our operations and future plans. Such forward-looking statements generally are accompanied by words such as plan, estimate, expect, predict, antici projected, should, assume, believe, target, or other words that convey the uncertainty of future events or out Such forward-looking information is based upon management s current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for our oil and natural gas; unexpected difficulties in integrating the operations of Denbury and Encore; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets; general economic conditions; competition and government regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and natural gas drilling and production activities or which are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

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DENBURY RESOURCES INC.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Long-Term Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies. The fair value of the subordinated debt is based on quoted market prices. The following table presents the carrying and fair values of our debt, along with average interest rates at March 31, 2011:

	Expected Maturity Dates							Carrying	Fair
In thousands, except percentages	2013	2014	2015	2016	2017	2020	2021	Value	Value
Variable rate debt:									
Bank Credit Agreement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed rate debt:									
7.5% Senior Subordinated Notes due 2013[(1)]	55,448	-	-	-	-	-	-	55,352	55,448
9.5% Senior Subordinated Notes due 2016	-	-	-	224,920	-	-	-	238,826	253,597
9.75% Senior Subordinated Notes due 2016	-	-	-	426,350	-	-	-	405,283	480,710
8.25% Senior Subordinated Notes due 2020	-	-	-	-	-	996,273	-	996,273	1,113,335
6.375% Senior Subordinated Notes due 2021	-	-	-	-	-	-	400,000	400,000	410,000
Other Subordinated Notes	-	1,072	485	-	2,250	-	-	3,845	3,807

(1) These notes were repurchased on April 1, 2011. See Note 3, *Long-Term Debt*, to the Unaudited Condensed Consolidated Financial Statements, for further information.

Commodity Derivative Contracts and Commodity Price Sensitivity

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production for a period generally ranging from approximately 12 to 18 months in advance (although we will hedge farther in advance if deemed prudent), as we believe it is important to protect our future cash flow for a short period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times. See Note 4, *Derivative Instruments and Hedging Activities,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification. All of our commodity derivative contracts are with parties that are lenders under our bank credit agreement. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our commodity derivative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At March 31, 2011, our commodity derivative contracts were recorded at their fair value, which was a net liability of approximately $216.3 million (excluding $21.2 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 significant change from the $44.0 million fair value liability recorded at December 31, 2010. This change is primarily related to the oil futures prices as of March 31, 2011 in relation to the commodity derivative contracts for 2011 through 2012.

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Based on NYMEX crude oil and natural gas futures prices as of March 31, 2011, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as seen in the following table:

In thousands	Crude Oil Derivative Contracts (Payment)	Natural Gas Derivative Contracts Receipt
Based on:		
NYMEX futures prices as of March 31, 2011	$ (120,867)	$ 30,033
10% increase in prices	(308,210)	21,692
10% decrease in prices	(11,555)	38,358

Equity Price Sensitivity

Our investment in Vanguard common units is considered an investment in available-for-sale securities, which are recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. This investment is thus subject to equity price sensitivity, as fair value is determined by quoted market prices. We estimate that a hypothetical 10% increase or decrease in quoted market prices for Vanguard common units would result in a $10.0 million unrealized gain or loss, respectively, as of March 31, 2011.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company s management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, the Company s Chief Executive Officer and our Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of March 31, 2011 to ensure: that information required to be disclosed in the reports it files and submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company s management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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

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DENBURY RESOURCES INC.
PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

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

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

Issuer Purchases of Equity Securities

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

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
January 2011	84,250	$ 19.76	-	$ -
February 2011	36,513	22.46	-	-
March 2011	208,893	24.31	-	-
Total	329,656	22.94	-	$ -

Item 6. Exhibits

Exhibit	Description
10(a)* **	Form of 2011 Performance Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(b)* **	Form of 2011 Performance Cash Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

* Filed herewith.

** Compensation arrangements.

DENBURY RESOURCES INC.
SIGNATURES

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

DENBURY RESOURCES INC.

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

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

Date: May 10, 2011