DENBURY RESOURCES INC
Form 10-Q
November 08, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

þ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2012

o Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from _______ to ________

Commission file number: 001-12935

DENBURY RESOURCES INC.
(Exact name of registrant as specified in its charter)

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

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

Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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

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

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

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

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

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

Class	Outstanding at October 31, 2012
Common Stock, $.001 par value	386,996,454

Denbury Resources Inc.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2012	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 24,034	$ 18,693
Accrued production receivable	290,805	294,689
Trade and other receivables, net	149,096	164,446
Short-term investments	—	86,682
Derivative assets	16,820	47,402
Deferred tax assets	18,168	50,156
Other current assets	9,845	22,045
Total current assets	508,768	684,113
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	8,230,939	7,026,579
Unevaluated	807,064	1,157,106
CO2 properties	687,890	596,003
Pipelines and plants	1,933,807	1,701,756
Other property and equipment	402,908	157,674
Less accumulated depletion, depreciation, amortization, and impairment	(3,080,957)	(2,627,493)
Net property and equipment	8,981,651	8,011,625
Derivative assets	12,820	29
Goodwill	1,363,547	1,236,318
Other assets	239,160	252,339
Total assets	$ 11,105,946	$ 10,184,424
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 403,396	$ 429,336
Oil and gas production payable	200,184	197,092
Derivative liabilities	2,395	26,523
Current maturities of long-term debt	36,635	8,316
Total current liabilities	642,610	661,267
Long-term liabilities		
Long-term debt, net of current portion	3,038,865	2,669,729
Asset retirement obligations	88,189	88,726
Derivative liabilities	1,999	18,872
Deferred taxes	2,095,850	1,918,576

Other liabilities		19,213		20,756
Total long-term liabilities		5,244,116		4,716,659
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; 405,399,728 and 402,946,070 shares issued, respectively		405		403
Paid-in capital in excess of par		3,132,342		3,090,374
Retained earnings		2,320,174		1,909,475
Accumulated other comprehensive loss		(366)		(418)
Treasury stock, at cost, 16,282,108 and 13,965,673 shares, respectively		(233,335)		(193,336)
Total stockholders' equity		5,219,220		4,806,498
Total liabilities and stockholders' equity	$	11,105,946	$	10,184,424

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Denbury Resources Inc.

Unaudited Condensed Consolidated Statements of Operations
(In thousands, except per share data)

	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
Revenues and other income				
Oil, natural gas, and related product sales	$ 588,156	$ 565,523	$ 1,813,798	$ 1,662,814
CO2 sales and transportation fees	7,160	6,541	19,256	16,808
Interest income and other income	5,055	4,441	14,214	12,445
Total revenues and other income	600,371	576,505	1,847,268	1,692,067
Expenses				
Lease operating expenses	130,485	133,285	392,960	383,167
Marketing expenses	14,728	6,416	37,776	17,989
CO2 discovery and operating expenses	1,176	1,250	8,443	4,889
Taxes other than income	40,012	36,180	122,518	108,295
General and administrative	38,198	26,613	109,631	97,641
Interest, net of amounts capitalized of $19,437, $17,853, $57,357 and $42,004, respectively	37,827	37,617	115,745	128,643
Depletion, depreciation, and amortization	136,935	101,978	390,119	299,067
Derivatives expense (income)	61,631	(210,154)	(32,203)	(212,308)
Loss on early extinguishment of debt	—	—	—	16,131
Impairment of assets	—	—	17,515	—
Other expenses	—	—	23,272	4,377
Total expenses	460,992	133,185	1,185,776	847,891
Income before income taxes	139,379	443,320	661,492	844,176
Income tax provision	54,012	167,650	250,793	323,450
Net income	$ 85,367	$ 275,670	$ 410,699	$ 520,726
Net income per common share – basic	$ 0.22	$ 0.69	$ 1.06	$ 1.31
Net income per common share – diluted	$ 0.22	$ 0.68	$ 1.05	$ 1.29
Weighted average common shares outstanding				
Basic	387,512	399,040	387,015	398,371
Diluted	390,909	403,311	390,854	403,575

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income	$ 85,367	$ 275,670	$ 410,699	$ 520,726
Other comprehensive income (loss), net of income tax:				
Net unrealized loss on available-for-sale securities, net of tax benefit of $2,420 and $4,244, respectively	—	(3,949)	—	(6,925)
Interest rate lock derivative contracts reclassified to income, net of tax of $11, $11, $32 and $32, respectively	17	17	52	52
Total other comprehensive income (loss)	17	(3,932)	52	(6,873)
Comprehensive income	$ 85,384	$ 271,738	$ 410,751	$ 513,853

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)

	Nine Months Ended September 30, 2012	2011
Cash flows from operating activities		
Net income	$410,699	$520,726
Adjustments needed to reconcile to net cash flow provided by operations:		
Depletion, depreciation, and amortization	390,119	299,067
Deferred income taxes	216,959	317,601
Stock-based compensation	22,662	27,520
Noncash fair value derivative adjustments	(19,757)	(217,008)
Loss on early extinguishment of debt	—	16,131
Amortization of debt issuance costs and discounts	11,021	13,280
Impairment of assets	17,515	—
Other, net	15,087	(4,340)
Changes in operating assets and liabilities:		
Accrued production receivable	3,221	(45,017)
Trade and other receivables	11,010	(38,607)
Other current and long-term assets	8,218	(11,587)
Accounts payable and accrued liabilities	(30,127)	(65,407)
Oil and natural gas production payable	5,014	40,819
Other liabilities	(35,515)	(14,086)
Net cash provided by operating activities	1,026,126	839,092
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(848,618)	(741,256)
Acquisitions of oil and natural gas properties	(155,636)	(34,291)
Cash paid in Riley Ridge acquisition	—	(199,233)
CO2 capital expenditures	(93,945)	(62,546)
Pipelines and plants capital expenditures	(231,459)	(142,406)
Purchases of other assets	(18,666)	(25,211)
Net proceeds from sales of oil and natural gas properties and equipment	33,973	47,598
Proceeds from sale of short-term investments	83,545	—
Other	(7,166)	(907)
Net cash used for investing activities	(1,237,972)	(1,158,252)
Cash flows from financing activities:		
Bank repayments	(970,000)	(255,000)
Bank borrowings	1,210,000	365,000
Repayment of senior subordinated notes	—	(525,000)
Premium paid on repayment of senior subordinated notes	—	(13,137)
Net proceeds from issuance of senior subordinated notes	—	400,000
Net proceeds from issuance of common stock	12,579	12,348
Costs of debt financing	(17)	(13,104)
Common stock repurchase program	(16,747)	—
Other	(18,628)	(9,453)
Net cash provided by (used for) financing activities	217,187	(38,346)

Net increase (decrease) in cash and cash equivalents	5,341	(357,506)
Cash and cash equivalents at beginning of period	18,693	381,869
Cash and cash equivalents at end of period	$24,034	$24,363

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

Denbury Resources Inc., a Delaware corporation, is a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis on our CO2 tertiary recovery operations.

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and do not include all of the information and footnotes required by Accounting Principles Generally Accepted in the United States ("U.S. GAAP") for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2011. Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company," or "Denbur refer to Denbury Resources Inc. and its subsidiaries.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year-end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of September 30, 2012, our consolidated results of operations for the three and nine months ended September 30, 2012 and 2011, and our consolidated cash flows for the nine months ended September 30, 2012 and 2011.

Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter. On the Unaudited Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2011, "Taxes other than income" is a new line item and includes (i) oil and natural gas ad valorem taxes, which were reclassified from "Lease operating expenses," (ii) franchise taxes and property taxes on buildings, which were reclassified from "General and administrative," (iii) oil and natural gas production taxes, which were reclassified from "Production taxes and marketing expenses" used in prior reports and (iv) CO2 property ad valorem and production taxes, which were classified from "CO2 discovery and operating expenses." Such reclassifications had no impact on our reported total expenses or net income.

Net Income per Common Share

Basic net income per common share is computed by dividing net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but includes the effect of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights ("SARs"), nonvested restricted stock, and nonvested performance equity awards. For the three and nine months ended September 30, 2012 and 2011, there were no adjustments to net income for purposes of calculating diluted net income per common share.

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Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2012	2011	2012	2011
Basic weighted average common shares	387,512	399,040	387,015	398,371
Potentially dilutive securities:				
Stock options and SARs	2,302	2,954	2,759	3,818
Performance equity awards	78	41	75	22
Restricted stock	1,017	1,276	1,005	1,364
Diluted weighted average common shares	390,909	403,311	390,854	403,575

Basic weighted average common shares excludes 3.6 million and 3.7 million shares for the three and nine months ended September 30, 2012, respectively, and 3.4 million and 3.5 million shares for the three and nine months ended September 30, 2011, respectively, of nonvested restricted stock. As these restricted shares vest or become retirement eligible, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares, the nonvested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2012	2011	2012	2011
Stock options and SARs	5,375	4,731	4,140	3,108
Restricted stock	69	139	63	56

Short-Term Investments

Short-term investments are available-for-sale securities recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. At December 31, 2011, short-term investments consisted entirely of our investment in Vanguard Natural Resources LLC (“Vanguard”) common units obtained as partial consideration for the sale of our interests in Encore Energy Partners LP to a subsidiary of Vanguard on December 31, 2010. We received distributions of $1.8 million and $5.3 million on the Vanguard common units we owned during the three and nine months ended September 30, 2011, respectively, which are included in “Interest income and other income” on our Unaudited Condensed Consolidated Statements of Operations. During January 2012, the Company sold its investment in Vanguard for cash consideration of $83.5 million, net of related transaction fees. The Company recognized a pretax loss on the sale of $3.1 million, which is included in “Other expenses” on our Unaudited Condensed Consolidated Statements of Operations for the nine months ended September 30, 2012.

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Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Goodwill

The following table summarizes the changes in Denbury's goodwill for the period indicated:

In thousands	Nine Months Ended September 30, 2012
Balance, beginning of period	$1,236,318
Goodwill related to the acquisition of interests in Thompson Field(1)	127,229
Balance, end of period	$1,363,547

(1) See Note 2, Acquisitions and Divestitures, for additional information regarding goodwill associated with Thompson Field.

Recently Adopted Accounting Pronouncements

Comprehensive Income. In June 2011, the Financial Accounting Standards Board ("FASB") issued ASU 2011-05, Presentation of Comprehensive Income ("ASU 2011-05"). ASU 2011-05 requires the presentation of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. ASU 2011-05 was effective for Denbury beginning January 1, 2012. Since ASU 2011-05 only amended presentation requirements, it did not have a material effect on our consolidated financial statements.

Fair Value. In May 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"). ASU 2011-04 amends the Financial Accounting Standards Board Codification ("FASC") Fair Value Measurements topic by providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the fair value disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 was effective for Denbury beginning January 1, 2012. The adoption of ASU 2011-04 did not have a material effect on our consolidated financial statements, but did require additional disclosures. See Note 6, Fair Value Measurements.

Note 2. Acquisitions and Divestitures

Pending Exchange Transaction

On September 19, 2012, we entered into a definitive exchange agreement with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") to sell ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for total consideration consisting of $1.6 billion cash (subject to closing adjustments), and ExxonMobil's operating interests in the Webster Field in Texas and the Hartzog Draw Field in Wyoming (the "Pending Exchange Transaction"). The Pending Exchange Transaction is expected to close around the end of November 2012 with an effective date of July 1, 2012 and is subject to customary closing conditions, including satisfactory completion of customary title and environmental due diligence. The cash portion of the sales price is subject to adjustments for revenues and costs of the respective assets from the effective date to the closing date. The

Pending Exchange Transaction agreement contains termination rights for both parties, including such rights based on the failure to close the transaction by January 31, 2013.

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Acquisitions

June 2012 Acquisition of Reserves in the Gulf Coast region at Thompson Field

In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after preliminary closing adjustments. The field is located approximately 18 miles west of Hastings Field, which is an enhanced oil recovery ("EOR") field that Denbury is currently flooding with CO2, and is the current terminus of the Green Pipeline which transports CO2 from the Jackson Dome, located near Jackson, Mississippi. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also expected to be an ideal candidate for a CO2 flood. Under the terms of the Thompson Field acquisition agreement, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d after the initiation of CO2 injection.

This acquisition meets the definition of a business under the FASC Business Combinations topic. As such, Denbury estimated the fair value of assets acquired and liabilities assumed as of June 1, 2012, the closing date of the acquisition. The FASC Fair Value Measurements and Disclosures topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific assumptions should not impact the measurement of fair value unless those assumptions are consistent with market participant views.

In applying these accounting principles, Denbury estimated the fair value of the assets acquired less liabilities assumed on the acquisition date to be approximately $238.9 million. This measurement resulted in the recognition of goodwill of approximately $127.2 million, which represents the excess of the cash paid to acquire the field over the acquisition date estimated fair value. This resultant goodwill is due primarily to two factors. The first factor is the decrease in average NYMEX oil futures prices between the date of signing the purchase agreement on April 24, 2012 and closing the purchase on June 1, 2012. The second factor is the fair value assigned to the estimated oil reserves recoverable through a CO2 EOR project. By building an 18-mile extension of the Green Pipeline, Denbury will have access to its CO2 reserves at Jackson Dome, one of the few known significant natural sources of CO2 in the United States, and the largest known source east of the Mississippi River, allowing Denbury to carry out CO2 EOR activities in this field at a lower cost than other market participants. However, the FASC Fair Value Measurements and Disclosures does not allow entity-specific assumptions in the measurement of fair value. Therefore, we estimated the fair value of the oil reserves recoverable through CO2 EOR using a higher estimated cost of CO2 to other market participants, which lowers the discounted net revenue stream used in making the fair value estimate related to this field.

The fair value of Thompson Field assets acquired and liabilities assumed was based on significant inputs not observable in the market, which FASC Fair Value Measurements and Disclosures topic defines as Level 3 inputs. Key assumptions include (1) NYMEX oil futures prices (this input is observable), (2) estimated quantities of oil reserves, (3) projections of future rates of production, (4) timing and amount of estimated future development and operating costs, (5) projected cost of CO2 to a market participant, (6) projected recovery factors, and (7) risk-adjusted discount rates. The fair value of the oil and natural gas properties was determined using a risk-adjusted after-tax discounted cash flow analysis. Denbury applies full cost accounting rules, and all of the goodwill is deductible for tax purposes as property cost.

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Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

The following table presents a summary of the preliminary fair value of the Thompson Field assets acquired and liabilities assumed.

In thousands		
Consideration:		
Cash payment(1)	$	366,178
Less: Fair value of assets acquired and liabilities assumed:(2)		
Oil and natural gas properties		
Proved		232,467
Unevaluated		4,151
Pipelines and plants		2,000
Other assets		3,637
Asset retirement obligations		(3,306)
		238,949
Goodwill	$	127,229

(1) See Divestitures below for additional information regarding restricted cash and the like-kind exchange transaction utilized to fund the purchase.
(2) Fair value of the assets acquired and liabilities assumed is preliminary, pending final closing adjustments and further evaluation of reserves and asset retirement obligations.

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

In August 2011, we acquired the remaining 57.5% working interest in the Riley Ridge Federal Unit (“Riley Ridge”), located in the LaBarge Field of southwestern Wyoming. Riley Ridge contains natural gas resources, as well as helium and CO2 resources. The purchase included a 57.5% interest in a gas plant which will separate the helium and natural gas from the commingled gas stream, and interests in certain surrounding properties. We previously acquired the other 42.5% interest in Riley Ridge and the gas plant in October 2010. The purchase price for the August 2011 acquisition was approximately $214.8 million after closing adjustments, including a $15.0 million deferred payment to be made at the time the Riley Ridge gas plant is operational and meets specific performance conditions. The gas plant is currently undergoing readiness testing, and we expect it to become operational in mid-2013.

The August 2011 acquisition of Riley Ridge meets the definition of a business under the FASC Business Combinations topic. The fair values assigned to assets acquired and liabilities assumed in the August 2011 acquisition have been finalized and no adjustments have been made to fair value amounts previously disclosed in our Form 10-K for the period ended December 31, 2011.

Pro Forma Information

Based on the immateriality of revenues and expenses related to the combined acquisitions of Thompson and Riley Ridge during the periods presented, pro forma information has not been disclosed.

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Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Divestitures

In February 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155.0 million to a privately held entity in which a member of our Board of Directors serves as chairman of the board, in a sale for which there was a competing bid contained in a multi-property purchase proposal. We realized net proceeds of $141.8 million, after final closing adjustments. The sale had an effective date of December 1, 2011 and consequently, operating revenues of $13.5 million after the effective date, net of capital and lease operating expenditures, along with any other purchase price adjustments, were adjustments to the selling price.

In April 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $75.0 million. The sale had an effective date of January 1, 2012 and proceeds received after consideration of final closing adjustments totaled $68.5 million. Closing adjustments included operating net revenues after January 1, 2012, net of capital and lease operating expenditures, along with other purchase price adjustments.

We did not record a gain or loss on either of the above sales of properties in accordance with the full cost method of accounting.

Of the proceeds from these property sales before final closing adjustments, $212.5 million was paid directly to a qualified intermediary and later released to fund a portion of the acquisition cost of Thompson Field (see June 2012 Acquisition of Reserves in the Gulf Coast region at Thompson Field above). Since the $212.5 million in cash proceeds was paid to a qualified intermediary in order to enable a like-kind exchange transaction for federal income tax purposes, this amount is not reflected as a receipt of cash from the sale of oil and natural gas properties and equipment, nor as a cash payment to purchase oil and natural gas properties in the investing activity in our Consolidated Statement of Cash Flows.

Note 3. Long-Term Debt

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

In thousands	September 30, 2012	December 31, 2011
Bank Credit Facility	$625,000	$385,000
9½% Senior Subordinated Notes due 2016, including premium of $9,802 and $11,854, respectively	234,722	236,774
9¾% Senior Subordinated Notes due 2016, including discount of $14,640 and $17,854, respectively	411,710	408,496
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 % Senior Subordinated Notes due 2021	400,000	400,000
Other Subordinated Notes, including premium of $27 and $33, respectively	3,834	3,840
NEJD Pipeline financing	160,684	163,677
Free State Pipeline financing	77,830	79,597
Capital lease obligations	165,447	4,388
Total	3,075,500	2,678,045
Less current obligations	(36,635)	(8,316)

Long-term debt and capital lease obligations	$3,038,865	$2,669,729

The parent company, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. Certain of DRI's subsidiaries guarantee our debt. Each such subsidiary guarantor is 100% owned by DRI, and the guarantees are full and unconditional and joint and several obligations of the subsidiary guarantors. Any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries.

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Bank Credit Facility

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A. as administrative agent, and other lenders party thereto (as amended the "Bank Credit Agreement"). Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semi-annually on or prior to May 1 and November 1 of each year, and is subject to requested special redeterminations. In September 2012, the banks reaffirmed our borrowing base of $1.6 billion; our next semi-annual redetermination is scheduled to occur on or around May 1, 2013. The borrowing base is adjusted at the banks' discretion and is based in part upon certain external factors over which we have no control. The weighted average interest rate on borrowings under the credit facility, evidenced by the Bank Credit Agreement (the "Bank Credit Facility") was 2.0% for the nine months ended September 30, 2012. We incur a commitment fee on the unused portion of the Bank Credit Facility of either 0.375% or 0.5%, based on the ratio of outstanding borrowings under the Bank Credit Facility to the borrowing base. The Bank Credit Agreement is scheduled to mature in May 2016.

In November 2012, we entered into the Ninth Amendment to the Bank Credit Agreement (the "Ninth Amendment") pursuant to which certain provisions of the Bank Credit Agreement were amended to, among other things (i) permit the sale of the Bakken area assets (without any change in our borrowing base), and (ii) increase the amount of distributions Denbury may make to its equity holders, including the repurchase of our common stock and/or the making of cash dividends with respect thereto, from an aggregate amount of $500 million up to an aggregate amount of $1.2 billion during the term of the Bank Credit Agreement, subject, in the case of such distributions, to certain existing restrictions and conditions, including the absence of any default or borrowing base deficiency, availability of no less than 25% of the borrowing base and compliance with all financial covenants, in each case on a pro forma basis after giving effect to any such distribution. The Ninth Amendment also provided a limited waiver of any oil hedging noncompliance that may occur as a result of the Pending Exchange Transaction during the period commencing on the closing date of the Pending Exchange Transaction and continuing through and including December 31, 2013.

In July 2012, we entered into the Eighth Amendment to the Bank Credit Agreement (the "Eighth Amendment") permitting the Company to incur capital lease obligations in an aggregate amount outstanding at any time not to exceed $300 million. The Bank Credit Agreement permits the Company to incur up to $40 million of other unsecured debt, and prior to the effectiveness of the Eighth Amendment capital leases would have been captured in this permitted debt basket. The Bank Credit Agreement was amended concurrent with the Company's change in classification of equipment leases from operating to capital in the second quarter of 2012 (see Capital Leases below), and the Eighth Amendment included the granting by the lenders of a waiver of any applicable violations of the provisions of the Bank Credit Agreement resulting from such correction and the Company's recording of its equipment leases as debt. In April 2012, we entered into the Seventh Amendment to the Bank Credit Agreement (the "Seventh Amendment"). Under the Seventh Amendment, we increased the amount of additional permitted subordinated debt (other than refinancing debt) from $300.0 million to $650.0 million.

6 % Senior Subordinated Notes due 2021

In February 2011, we issued $400.0 million of 6 % Senior Subordinated Notes due 2021 ("2021 Notes"). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393.0 million were used to repurchase a portion of our outstanding 2013 Notes and 2015 Notes (see Redemption of our 2013 and 2015 Notes below).

Redemption of our 2013 and 2015 Notes

Pursuant to cash tender offers, during March 2011, we repurchased $169.6 million in principal of our 7½% Senior Subordinated Notes due 2013 ("2013 Notes") at 100.625% of par, and $220.9 million in principal of our 7½% Senior Subordinated Notes due 2015 ("2015 Notes") at 104.125% of par. We called the remaining 2013 Notes and 2015 Notes, repurchasing all of the remaining outstanding 2015 Notes ($79.1 million) at 103.75% of par on March 21, 2011 and all of the remaining outstanding 2013 Notes ($55.4 million) at par on April 1, 2011. We recognized a $16.1 million loss during the nine months ended September 30, 2011 associated with the debt repurchases, which is included in our Unaudited Condensed Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt."

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Capital Lease Obligations

During the second quarter of 2012, we corrected the accounting for our equipment leases from operating leases to capital leases to comply with ASC Topic 840, Leases as a result of the consideration of nonperformance-related default covenants included in our equipment lease agreements. We recorded a cumulative adjustment to establish the capital lease assets as “Other property and equipment” ($155.6 million) and the capital lease obligations as “Long-term debt” ($138.9 million) and “Current maturities of long-term debt” ($25.1 million) on the accompanying Unaudited Condensed Consolidated Balance Sheets. We also recognized the cumulative pre-tax impact of $8.4 million ($5.2 million after tax) as “Other expenses” on the accompanying Unaudited Condensed Consolidated Statements of Operations for the nine months ended September 30, 2012. Because the amounts involved were not material to the Company’s financial statements in any individual prior period, and the cumulative impact is not material to the estimated results of operations for the year ending December 31, 2012, we recorded the cumulative effect of correcting these items during the second quarter of 2012.

Note 4. Stockholders’ Equity

Stock Repurchase Program

In October 2011, we commenced a common stock repurchase program for up to $500 million of Denbury common stock, as approved by the Company’s Board of Directors. The program has no pre-established ending date, and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

During the third quarter of 2012, we repurchased 2,493,435 shares of Denbury common stock for $41.1 million, or $16.48 per share, and in October 2012, we repurchased an additional 2,133,910 shares for $34.9 million, or $16.35 per share. Since commencement of the share repurchase program in October 2011, we have purchased a total of 18,739,955 shares of Denbury common stock for $271.2 million and thus are authorized to spend an additional $228.8 million under this repurchase program. We account for treasury stock using the cost method and include treasury stock as a component of stockholders’ equity.

Note 5. Derivative Instruments

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

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

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

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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:

In thousands	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Oil				
Payment on settlements of derivative contracts	$ 641	$ 1,857	$ 9,580	$ 23,857
Fair value adjustments to derivative contracts – expense (income)	60,726	(205,355)	(37,752)	(225,485)
Total derivatives expense (income) – oil	61,367	(203,498)	(28,172)	(201,628)
Natural Gas				
Receipt on settlements of derivative contracts	(6,910)	(6,427)	(21,941)	(19,073)
Fair value adjustments to derivative contracts – expense (income)	7,174	(229)	17,910	8,393
Total derivatives expense (income) – natural gas	264	(6,656)	(4,031)	(10,680)
Derivatives expense (income)	$ 61,631	$ (210,154)	$ (32,203)	$ (212,308)

Commodity Derivative Contracts Not Classified as Hedging Instruments

The following tables present outstanding commodity derivative contracts with respect to future production as of September 30, 2012:

Year	Months	Type of Contract	Volume(1)	Contract Prices(2) Range	Weighted Average Price Swap	Weighted Average Price Floor	Weighted Average Price Ceiling
Oil Contracts:							
2012	Oct – Dec	Swap	625	$ 80.28 – 81.75	$ 81.04	$ —	$ —
		Collar	53,000	80.00 – 140.65	—	80.00	128.57
		Put	625	65.00 – 65.00	—	65.00	—
	Total Oct – Dec 2012		54,250				
2013	Jan – Mar	Collar	55,000	$ 70.00 – 113.00	$ —	$ 78.91	$ 108.01
	Apr – June	Collar	56,000	75.00 – 121.50	—	79.64	108.61
	July – Sept	Collar	56,000	75.00 – 133.10	—	79.64	109.15

	Oct – Dec	Collar	54,000	80.00 – 127.50	—	80.00	117.53
2014	Jan – Mar	Collar	46,000	$ 80.00 – 104.50	$ —	$ 80.00	$ 103.13
	Apr – June	Collar	46,000	80.00 – 104.50	—	80.00	103.13
Natural Gas Contracts:							
2012	Oct – Dec	Swap	20,000	$ 6.30 – 6.85	$ 6.53	$ —	$ —

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

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

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Notes to Unaudited Condensed Consolidated Financial Statements

During the third quarter of 2012, we restructured most of our oil derivative collar contracts for the first three quarters of 2013 to increase the weighted average floor price to approximately $80 per Bbl and decrease the weighted average ceiling price. These updated contracts are reflected in the table above.

Additional Disclosures about Derivative Instruments

At September 30, 2012 and December 31, 2011, we had derivative financial instruments recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

		Estimated Fair Value Asset (Liability)	
Type of Contract	Balance Sheet Location	September 30, 2012	December 31, 2011
		In thousands	
Derivatives not designated as hedging instruments:			
Derivative asset			
Crude oil contracts	Derivative assets – current	$ 10,780	$ 23,452
Natural gas contracts	Derivative assets – current	6,040	23,950
Crude oil contracts	Derivative assets – long-term	12,820	29
Derivative liability			
Crude oil contracts	Derivative liabilities – current	(1,680)	(22,610)
Deferred premiums(1)	Derivative liabilities – current	(715)	(3,913)
Crude oil contracts	Derivative liabilities – long-term	(1,999)	(18,702)
Deferred premiums(1)	Derivative liabilities – long-term	—	(170)
Total derivatives not designated as hedging instruments		$ 25,246	$ 2,036

(1) Deferred premiums payable relate to various oil floor contracts and are payable on a monthly basis through January 2013.

Note 6. Fair Value Measurements

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

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing. The Company's costless-collars are valued using the Black-Scholes model, an industry standard option valuation model, that takes into account inputs such as contractual prices for the underlying instruments, including maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

- Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Instruments in this category include non-exchange-traded natural gas derivatives swaps that are based on regional pricing other than NYMEX (i.e., Houston Ship Channel). The Company's basis swaps are estimated using discounted cash flow calculations based upon forward commodity price curves. Significant increases or decreases in forward commodity price curves would result in a significantly higher or lower fair value measurement.

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

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of the periods indicated:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
September 30, 2012				
Assets				
Oil and natural gas derivative contracts	$ —	$ 23,600	$ 6,040	$ 29,640
Liabilities				
Oil and natural gas derivative contracts	—	(3,679)	—	(3,679)
Total	$ —	$ 19,921	$ 6,040	$ 25,961
December 31, 2011				
Assets				
Short-term investments	$ 86,682	$ —	$ —	$ 86,682
Oil and natural gas derivative contracts	—	23,481	23,950	47,431
Liabilities				
Oil and natural gas derivative contracts	—	(41,312)	—	(41,312)
Total	$ 86,682	$ (17,831)	$ 23,950	$ 92,801

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.

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Notes to Unaudited Condensed Consolidated Financial Statements

Level 3 Fair Value Measurements

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following table summarizes the changes in the fair value of our Level 3 assets for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2012	2011	2012	2011
Balance, beginning of period	$13,214	$6,638	$23,950	$16,478
Unrealized gains (losses) on commodity derivative contracts included in earnings	(264)	1,717	4,031	(5,359)
Receipts on settlement of commodity derivative contracts	(6,910)	(1,378)	(21,941)	(4,142)
Balance, end of period	$6,040	$6,977	$6,040	$6,977

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

The following table details fair value inputs related to our Level 3 natural gas financial measurements:

In thousands	Fair Value at 9/30/2012	Valuation Technique	Unobservable Input	Range
Natural gas derivative contracts	$ 6,040	Discounted Cash Flow	Forward commodity price curve	(a)

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

Pricing Index	Settlement Period	Forward Pricing Range
TETCO M1	10/1/2012 – 12/31/2012	$2.92/MMBtu – $3.55/MMBtu
Houston Ship Channel	10/1/2012 – 12/31/2012	$2.98/MMBtu – $3.56/MMBtu
Natural Gas – Midcontinent	10/1/2012 – 12/31/2012	$2.77/MMBtu – $3.53/MMBtu

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

As of December 31, 2011, we had invested a total of $13.8 million in the preferred stock of Faustina Hydrogen Products LLC, a company created to develop a proposed gasification plant from which CO2 would be produced as a byproduct and used by Denbury in its tertiary oil operations. The investment was recorded at cost, together with a $1.3 million receivable for accrued dividends receivable. The developer of the proposed plant was soliciting other potential investors for the project, and as of December 31, 2011, a third-party was actively engaged in due diligence. During 2012, a key investor and participant in the project announced its intent to abandon its investment in the proposed plant. As a result, due diligence by the potential third party investor ceased. Absent the key investor, we believe it is unlikely the plant will be constructed, and therefore, it is also unlikely our investment will generate future cash flows. Accordingly, we recorded a $15.1 million impairment charge for this investment during the first quarter of 2012, which is classified as "Impairment of assets" in the Unaudited Condensed Consolidated Statement of Operations for the nine months ended September 30, 2012. The inputs used to determine fair value of the investment included the projected future cash flows of the plant and risk-adjusted rate of return that we estimated would be used by a market participant in valuing the asset. These inputs are unobservable within the marketplace and therefore considered Level 3 within the fair value hierarchy. However, as there are currently no expected future cash flows associated with the plant, the preferred stock was determined to have no value.

Other Fair Value Measurements

The carrying value of our Bank Credit Facility approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our senior subordinated notes as of September 30, 2012 and December 31, 2011 is $2,260.0 million and $2,253.2 million, respectively. The fair value hierarchy for long-term debt is primarily Level 1 (quoted prices for identical assets in active markets). We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 7. Commitments and Contingencies

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

Note 8. Related Party

During the three and nine months ended September 30, 2012, we purchased $4.5 million and $9.7 million, respectively of oil produced by a privately-held entity of which a member of our Board of Directors serves as chairman of the board. The oil purchased under this agreement is related to the non-core assets in central and southern Mississippi and in southern Louisiana (see further discussion in Note 2, Acquisitions and Divestitures) sold to this same entity in February 2012. The oil purchased under this agreement is part of a typical commercial transaction that would be entered into with a third party and is later blended with other oil and sold by Denbury to an unrelated third party. The purchase of oil is classified as “Marketing expenses” and the subsequent sale is included in “Interest income and other income” on the accompanying Unaudited Condensed Consolidated Statements of Operations. We are under no continuing obligation to purchase oil under this agreement.

Note 9. Subsequent Event

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

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Denbury Resources Inc.

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

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2011 (the "Form 10-K"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Form 10-K. Any terms used but not defined herein have the same meaning given to them in the Form 10-K. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Risk Factors under Item 1A of Part II of this report, along with Forward-Looking Information at the end of this Item 2 for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest CO2 reserves used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis on our CO2 tertiary recovery operations.

Operating Highlights

We recognized net income of $85.4 million, or $0.22 per basic common share, during the third quarter of 2012 compared to net income of $275.7 million, or $0.69 per basic common share, during the third quarter of 2011. This decrease in net income between the two periods is primarily attributable to a $273.5 million ($169.6 million after-tax) non-cash change in the fair value of the Company's commodity derivative contracts in the most recent quarter compared to the prior year third quarter, slightly offset by a 4% increase in oil and natural gas revenues due to higher production.

During the third quarter of 2012, our oil and natural gas production, which was 93% oil, averaged 72,776 BOE/d compared to 66,830 BOE/d produced during the third quarter of 2011. This 9% increase in production is primarily attributable to production increases in our tertiary oil fields and Bakken area assets, the latter of which are currently under contract to be sold, partially offset by normal declines in most of our other non-tertiary properties and a reduction from non-core properties sold in 2012 (see Pending Exchange Transaction and Sale of Non-Core Assets – First Half 2012 below). After adjusting quarterly production in both periods to exclude production from non-core properties which have been sold in 2012 and the planned Bakken area assets sale, production in the third quarter of 2012 increased 4% over production in the comparable prior year quarter and decreased 1% sequentially over levels in the second quarter of 2012. Our tertiary oil production averaged 34,786 Bbls/d during the third quarter of 2012, an increase of 12% over the 31,091 Bbls/d produced during the third quarter of 2011 and a decrease of 1% compared to second quarter 2012 levels. The slight decrease in sequential quarterly tertiary oil production between the second and third quarters of 2012 was principally due to shutting-in production at several fields due to Hurricane Isaac in late August. Production related to our Bakken area assets currently under contract to be sold averaged 16,651 BOE/d during the third quarter of 2012, an increase of 59% over production of 10,461 BOE/d during the third quarter of 2011 and an increase of 8% over second quarter 2012 levels. On an aggregate basis, sequential quarterly production was up slightly between the second and third quarters of 2012 principally due to a full quarter of production from Thompson Field (see Acquisition of Thompson Field – Second Quarter 2012 below) offset by required production shut-ins for Hurricane Isaac in late August. See Results of Operations – CO2 Operations and Results of Operations – Operating

Results – Production for more information.

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

Our average realized oil price received per barrel, excluding the impact of commodity derivative contracts, decreased 4% to $93.09 per Bbl during the third quarter of 2012, compared to $96.85 per Bbl during the third quarter of 2011. This decrease in realized oil prices was generally due to price changes in the markets in which we sell our crude oil, as NYMEX oil prices actually increased 3% between the respective third quarters of 2012 and 2011. Our average oil price differential compared to NYMEX prices was a positive $0.80 per Bbl in the third quarter of 2012 compared to a positive $7.25 per Bbl in the third quarter of 2011. See Results of Operations – Oil and Natural Gas Revenues below for more information on our oil prices received and differentials to NYMEX prices.

Pending Exchange Transaction

On September 19, 2012, we entered into a definitive exchange agreement with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") to sell ExxonMobil our Bakken assets in North Dakota and Montana in exchange for total consideration consisting of $1.6 billion in cash (subject to closing adjustments), and ExxonMobil's operating interests in the Webster Field in Texas and the Hartzog Draw Field in Wyoming (the "Pending Exchange Transaction"). The Pending Exchange Transaction is currently expected to close around the end of November 2012, with an effective date of July 1, 2012, and is subject to customary closing conditions, including satisfactory completion of customary title and environmental due diligence. The cash portion of the sales price is subject to adjustments for revenues and costs of the respective assets from the effective date to the closing date. We do not expect to record a gain or loss for financial statement purposes on the sale of the Bakken area assets in accordance with the full cost method of accounting, nor do we expect to record a reduction in goodwill in conjunction with the sale of the Bakken area assets. The Pending Exchange Transaction agreement contains termination rights for both parties, including such rights based on the failure to close the transaction by January 31, 2013.

Upon closing of the Pending Exchange Transaction, we would acquire a nearly 100% working interest and nearly 80% net revenue interest in the Webster Field located in southeastern Texas. Webster Field is similar to our Hastings and Thompson fields, producing oil from the Frio zone at similar depths, and is believed to be a potential candidate for CO_2 flooding. Webster Field is located approximately eight miles northeast of our Hastings CO_2 flood and the Green Pipeline, which transports CO_2 from our source in Mississippi.

With respect to the Hartzog Draw Field, we would acquire an 83% working interest and 71% net revenue interest in the oil producing Shannon Sandstone zone and a 67% working interest and 53% net revenue interest in the natural gas producing Big George Coal zone. Hartzog Draw Field is a potential candidate for CO_2 flooding and is located approximately 12 miles from the Greencore pipeline which, upon scheduled completion in 2012, will transport CO_2 from our source near Lost Cabin, Wyoming to Bell Creek Field in Montana.

The Company intends to structure the acquisition of interests in Webster and Hartzog Draw fields and the sale of our Bakken area assets as a like-kind exchange transaction for federal income tax purposes. Assuming no other qualifying purchases are made, we anticipate after-tax proceeds from the transaction (without giving effect to closing adjustments) will be approximately $1.1 billion. The Company is continuing to seek possible acquisitions in which proceeds from the Pending Exchange Transaction could be utilized in a like-kind exchange transaction to reduce the amount of federal income tax payable due to the transaction.

In addition, we have agreed to negotiate in good faith with ExxonMobil to reach an agreement on, and if agreed upon, execute a definitive document for, our potential purchase from ExxonMobil of either (i) an interest in CO_2 reserves in their LaBarge Field in southwestern Wyoming or (ii) incremental CO_2 from that field (the "LaBarge Transaction"). The

LaBarge Transaction is subject to our ability to reach mutually agreeable terms and conditions regarding the purchase with ExxonMobil.

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Denbury Resources Inc.

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Acquisition of Thompson Field – Second Quarter 2012

In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after preliminary closing adjustments. The field is located approximately 18 miles west of Denbury's Hastings Field which is currently being flooded with CO2, and which is the current terminus of the Green Pipeline which transports CO2 from Denbury's source in Jackson Dome, Mississippi. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also expected to be an ideal candidate for a CO2 flood. Under the terms of the agreement, after the initiation of CO2 injection, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d. We funded the purchase principally with cash proceeds from property sales earlier this year and the remainder from borrowings under our revolving credit facility.

Sale of Non-Core Assets – First Half 2012

On April 9, 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $75.0 million. The sale had an effective date of January 1, 2012, and proceeds realized after final closing adjustments totaled $68.5 million. On February 29, 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155.0 million. We realized net proceeds of $141.8 million, after final closing adjustments. We structured the sale of our non-core assets and the purchase of Thompson Field as a like-kind exchange transaction for federal income tax purposes and anticipate deferral of a majority of the taxable gain recognized on the sale of the non-core assets. We did not record a gain or loss on either sale in accordance with the full cost method of accounting.

Sale of Investment in Vanguard Natural Resources LLC – First Quarter 2012

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

Addition of Proved Oil and Natural Gas Reserves

During the first nine months of 2012, we added 85.3 MMBOE of estimated proved reserves, including tertiary oil reserves of 42.6 MMBbls at Hastings Field and 14.1 MMBbls at Oyster Bayou Field based on these fields' responses to CO2 injections, 16.3 MMBOE due to further development in the Bakken, and 12.3 MMBOE of acquired reserves at Thompson Field. These increases were partially offset by the disposition of 12.7 MMBOE of reserves associated with the sale of non-core assets above.

Capital Resources and Liquidity

We currently project that our 2012 capital budget will be $1.5 billion, which excludes estimated equipment leases ($75 million), acquisitions, capitalized interest and start-up costs associated with our new tertiary floods. Our current 2012 capital budget includes the following:

- $430 million allocated for tertiary oil field expenditures;

- $480 million for development of our Bakken properties;
- $290 million for pipeline construction;
- $200 million to be spent on CO_2 sources; and
- $100 million to be spent in all other areas.

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Based on oil and natural gas prices in early November 2012 and our current production forecasts, we estimate that our 2012 capital budget (including capitalized interest and tertiary start-up costs) will be approximately $200 to $300 million greater than our 2012 anticipated cash flow from operations. We plan to fund any shortfall between our cash flow from operations and our capital spending with proceeds from our asset sales and borrowings under our bank credit facility.

During the first nine months of 2012, we incurred capital expenditures of approximately $1.1 billion, net of equipment lease recoveries of $35.1 million. Additionally, we have capitalized interest and tertiary start-up costs which are not included in the above mentioned amounts. See additional detail on our expenditures in the table below under Capital Expenditure Summary. Our original estimate of completing $75 million of equipment sale leasebacks in 2012 to finance a portion of our capital spending was based on an expectation that our Riley Ridge facility would be operational in 2012. As we now estimate that Riley Ridge will not be operational until mid-2013, we currently project that our equipment sale leasebacks in 2012 will total less than $40 million.

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. We currently do not anticipate any material changes to our 2012 capital spending plans. For 2013, we will attempt to match our capital spending within a close range of projected cash flow from operations. As a result of the Pending Exchange Transaction above, we may have up to $1.1 billion of incremental cash if we are not able to consummate any additional asset purchases that would qualify under a like-kind exchange transaction. We would plan to use any such excess cash in a variety of ways, which among other things, could include paying down our debt or funding our capital development program. Additionally, we may choose to repurchase additional shares of common stock.

For 2012 and certain future years, we have contracted for certain capital expenditures; therefore, we cannot eliminate all of our capital commitments without penalties (refer to Management's Discussion and Analysis – Capital Resources and Liquidity – Off-Balance Sheet Arrangements – Commitments and Obligations in the Form 10-K). In addition to the potential flexibility in our capital spending plans, as of September 30, 2012, we had approximately $1.0 billion of unused availability under our bank credit facility and have oil price floors in place through mid-2014 (see Note 5, Derivative Instruments, to the Unaudited Condensed Consolidated Financial Statements), which together should provide us with adequate liquidity and flexibility to meet our near-term capital spending plans if oil prices were to decrease significantly. Also, as part of the Pending Exchange Transaction, our banking syndicate has approved the transaction and our borrowing base remains unchanged at $1.6 billion. We currently believe we could increase the borrowing base under our bank credit facility above the current $1.6 billion level if we desired to do so.

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Capital Expenditure Summary

The following table of capital expenditures includes accrued capital for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30,	
In thousands	2012	2011
Capital expenditures by project:		
Tertiary oil fields	$ 340,698	$ 380,029
Bakken	338,242	297,640
CO_2 pipelines	114,738	81,335
CO_2 sources (1)	186,836	75,209
Other areas	114,478	167,167
Capital expenditures before acquisitions and capitalized interest	1,094,992	1,001,380
Less: recoveries from sale/leaseback transactions	(35,102)	(42,582)
Net capital expenditures excluding acquisitions and capitalized interest	1,059,890	958,798
Acquisitions:		
Property acquisitions (2)	369,580	34,291
Consideration for August 2011 Riley Ridge acquisition	—	214,554
Capitalized interest	57,357	42,004
Capital expenditures, net of sale/leaseback transactions	$ 1,486,827	$ 1,249,647

(1) Includes capital expenditures related to the Riley Ridge gas plant.
(2) Includes capital expenditures of $212.5 million that are not reflected as an Investing Activity on our Unaudited Condensed Consolidated Statements of Cash Flows due to the movement of proceeds through a qualified intermediary. See Note 2, Acquisitions and Divestitures to the Unaudited Condensed Consolidated Financial Statements.

Our capital expenditures for the first nine months of 2012 were funded with $1,026.1 million of cash flow from operations, $210.3 million of net proceeds (after final closing adjustments) from non-core oil and natural gas asset divestitures, $83.5 million of proceeds from the sale of our investment in Vanguard common units and the remainder with borrowings under our bank credit facility. Our capital expenditures, excluding the Riley Ridge acquisition, for the first nine months of 2011 were funded with $839.1 million of cash flow from operations and the remainder with cash on hand at the beginning of the period.

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Share Repurchase Program

We have an ongoing share repurchase program under which $500 million of share repurchases is authorized. During the third quarter of 2012, we repurchased 2,493,435 shares of Denbury common stock for $41.1 million, or $16.48 per share, and in October 2012, we repurchased an additional 2,133,910 shares of Denbury common stock for $34.9 million, or $16.35 per share. Since the commencement of the share repurchase program in October 2011, we have purchased a total of 18,739,955 shares of Denbury common stock (approximately 5% of Denbury's outstanding common stock as of September 30, 2011) for $271.2 million, or $14.47 per share, and thus are authorized to spend an additional $228.8 million under this repurchase program. The November 2012 amendments to our bank credit facility expanded the dollar amount of common stock we are permitted to purchase from an aggregate of $500 million to an amount of up to $1.2 billion (see Note 3, Long-Term Debt), giving us the flexibility to more easily expand the size of our repurchase program beyond the $500 million currently approved by our Board of Directors. Whether we make any share repurchases during the remainder of 2012 will be determined based on various parameters; therefore, it is uncertain whether or not we will make additional repurchases of Denbury common stock under this program in the remainder of 2012.

Off-Balance Sheet Arrangements

Our obligations that are not currently recorded on our balance sheet consist of 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 5 and 6 to the Unaudited Condensed Consolidated Financial Statements.

Our commitments and obligations consist of those detailed as of December 31, 2011 in the Form 10-K, subject to the correction in the classification of our equipment leases from operating to capital (see Note 3, Long-Term Debt), and subject to the change in future development costs due to the planned Bakken area assets sale (see Note 2, Acquisitions and Divestitures – Pending Exchange Transaction) under Management's Discussion and Analysis of Financial Condition and Results of Operations – Off-Balance Sheet Arrangements – Commitments and Obligations.

Results of Operations

CO2 Operations

Our focus on CO2 operations is the primary strategy of our business and operations. We believe there are significant additional oil reserves and production that can be obtained through the use of CO2, and we have outlined certain of this estimated potential in our Form 10-K and other public disclosures. In addition to its long-term effect, our focus on these types of operations impacts certain trends in our current and near-term operating results. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations and the section entitled CO2 Operations contained in our Form 10-K for further information regarding these matters.

CO2 Source Fields. During the third quarter of 2012, our CO2 production at Jackson Dome averaged 1,036 MMcf/d, compared to an average of 1,001 MMcf/d produced during the third quarter of 2011 and 915 MMcf/d produced during the second quarter of 2012. We used 90% of this production, or 937 MMcf/d, in our tertiary operations during the third quarter of 2012, and sold the balance to our industrial customers or to Genesis Energy, L.P. pursuant to our volumetric production payment contracts. Refer to Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Off-Balance Sheet Arrangements – Commitments and Obligations in our Form 10-K for further discussion of our CO2 delivery obligations. With the acquisition of Thompson Field in 2012 and the pending acquisition of Webster Field (see Pending Exchange Transaction above), we will likely need to develop some of our probable and possible CO2 reserves at Jackson Dome so that we have sufficient proved reserves to flood newly acquired fields. We anticipate an ongoing exploration and development program at Jackson Dome designed to increase both the CO2 production rate and proved reserves that will be available to us until substantial anthropogenic sources are developed, which is currently expected to first occur several years in the future. At December 31, 2011, our proven CO2 reserves at Jackson Dome were approximately 6.7 Tcf on a gross working interest basis, of which Denbury's net revenue interest was approximately 5.3 Tcf, and include reserves dedicated to volumetric production payments of 84.7 Bcf.

We spent approximately $0.27 per Mcf to produce and pay royalties and taxes for the CO2 we utilize in our tertiary floods during the first nine months of 2012, including $0.28 during the first quarter of 2012, $0.29 per Mcf during the second quarter of 2012, and $0.25 per Mcf during the third quarter of 2012. These rates have remained relatively consistent with the $0.26 per Mcf spent during the first nine months of 2011 and $0.24 per Mcf cost during the third quarter of 2011. Our estimated cost of CO2, after inclusion of depreciation and amortization expense related to the CO2 production but excluding depreciation of our CO2 pipelines, was $0.32 per Mcf and $0.33 per Mcf during the three and nine months ended September 30, 2012, respectively, compared to $0.30 per Mcf and $0.26 per Mcf during the same periods in 2011.

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Tertiary Production. The following table summarizes our tertiary oil production and tertiary lease operating expense per barrel for each quarter in 2011 and the first, second, and third quarters of 2012:

	Average Daily Production (Bbls/d)						
Tertiary Oil Field	First Quarter 2011	Second Quarter 2011	Third Quarter 2011	Fourth Quarter 2011	First Quarter 2012	Second Quarter 2012	Third Quarter 2012
Phase 1:							
Brookhaven	3,664	3,213	3,030	3,121	3,014	2,779	2,460
McComb area	2,161	1,983	2,005	1,843	1,746	1,902	1,769
Mallalieu area	2,925	2,646	2,620	2,587	2,585	2,461	2,181
Other	3,290	3,196	2,879	2,749	2,500	2,444	2,060
Phase 2:							
Heidelberg	3,374	3,548	3,141	3,728	3,583	3,823	3,716
Eucutta	3,247	3,114	2,985	3,139	3,090	2,870	2,782
Soso	2,582	2,317	2,331	2,162	2,063	1,947	1,923
Martinville	500	416	453	481	551	480	476
Phase 3:							
Tinsley	6,567	6,990	7,075	6,338	7,297	8,168	8,153
Phase 4:							
Cranfield	991	1,085	1,214	1,200	1,152	1,094	1,119
Phase 5:							
Delhi	1,524	2,263	3,358	3,778	4,181	4,023	3,813
Phase 7:(1)							
Hastings	—	—	—	—	618	1,913	2,794
Phase 8:							
Oyster Bayou	—	—	—	18	877	1,304	1,540
Total tertiary oil production (Bbl/d)	30,825	30,771	31,091	31,144	33,257	35,208	34,786
Tertiary lease operating expense per Bbl	$ 24.93	$ 22.87	$ 24.91	$ 23.59	$ 26.74	$ 22.95	$ 23.50

(1) As of September 30, 2012, we did not have any tertiary production from our fields in Phase 6, Citronelle Field, which will require an extension to the Free State CO2 Pipeline or another pipeline, depending on the ultimate CO2 source for this field, the timing of which is uncertain.

Oil production from our tertiary operations increased 12% to an average of 34,786 Bbls/d during the third quarter of 2012 compared to third quarter 2011 tertiary production levels, primarily due to production growth in response to continued expansion of the tertiary floods in Heidelberg, Tinsley and Delhi fields and production at our Oyster Bayou and Hastings CO2 fields, which experienced their initial tertiary production response in late December 2011 and early

January 2012, respectively. Offsetting third quarter production gains were production shut-ins due to Hurricane Isaac and declines in our more mature Phase 1 and Phase 2 fields.

Our tertiary oil production during the third quarter of 2012 decreased 422 Bbls/d compared to second quarter 2012 levels primarily as a result of Hurricane Isaac, which required us to temporarily shut-in production for several days in our Phase 1 and Phase 4 properties, and expected declines in our more mature fields in Phase 1 and Phase 2. These decreases were partially offset by continued increased production at our Hastings and Oyster Bayou fields. We expect our tertiary oil production to return to an upward trend in the fourth quarter, driven primarily by recent increases in Delhi Field. In October 2012, we estimate that our tertiary production averaged around 36,000 Bbls/d.

The production growth rate at a tertiary flood can vary from quarter to quarter as a tertiary field's production may increase rapidly when wells respond to the CO2, 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 CO2, as the CO2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. We find all of these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the entire field is developed, albeit sometimes in inconsistent patterns. Specifically, production at Tinsley Field increased rapidly during the first two quarters of 2012 after the field was re-pressurized late in 2011, and then remained steady during the third quarter of 2012 as production declines in older wells were offset by production increases in newly drilled wells.

During the third quarter of 2012, operating costs for our tertiary properties averaged $23.50 per Bbl, a 6% decrease from an average of $24.91 per Bbl during the third quarter of 2011 (although tertiary operating expenses increased 6% on an absolute basis) and only a slight increase from an average of $22.95 during the second quarter of 2012. The decrease in tertiary operating costs per barrel in the third quarter of 2012 compared to the same period in 2011 is due to the 12% increase in tertiary production, which more than offset the higher total tertiary operating expenses resulting from the increase in the number of our active tertiary floods due to our new tertiary floods at Hastings and Oyster Bayou fields. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially, as we experienced early in 2012 with our Oyster Bayou and Hastings floods, and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when lease operating expense per barrel will again increase.

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Operating Results

Certain of our operating results and statistics for the comparative third quarters and first nine months of 2012 and 2011 are included in the following table:

In thousands, except per share and unit data	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
Operating results				
Net income	$ 85,367	$ 275,670	$ 410,699	$ 520,726
Net income per common share – basic	0.22	0.69	1.06	1.31
Net income per common share – diluted	0.22	0.68	1.05	1.29
Net cash provided by operating activities	293,506	315,739	1,026,126	839,092
Average daily production volumes				
Bbls/d	67,655	61,984	67,331	60,007
Mcf/d	30,724	29,079	29,318	30,736
BOE/d(1)	72,776	66,830	72,217	65,129
Operating revenues				
Oil sales	$ 579,429	$ 552,281	$ 1,790,326	$ 1,621,047
Natural gas sales	8,727	13,242	23,472	41,767
Total oil and natural gas sales	$ 588,156	$ 565,523	$ 1,813,798	$ 1,662,814
Commodity derivative contracts(2)				
Cash receipt (payment) on settlement of commodity derivative contracts	$ 6,269	$ 4,570	$ 12,361	$ (4,784)
Non-cash fair value adjustment income (expense)	(67,900)	205,584	19,842	217,092
Total income (expense) from commodity derivative contracts	$ (61,631)	$ 210,154	$ 32,203	$ 212,308
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 93.09	$ 96.85	$ 97.04	$ 98.95
Natural gas price per Mcf	3.09	4.95	2.92	4.98
Unit prices – including impact of derivative settlements(2)				
Oil price per Bbl	$ 92.99	$ 96.52	$ 96.52	$ 97.50
Natural gas price per Mcf	5.53	7.35	5.65	7.25
Oil and natural gas operating expenses				
Lease operating expenses	$ 130,485	$ 133,285	$ 392,960	$ 383,167
Marketing expenses	14,728	6,416	37,776	17,989
Taxes other than income(3)	40,012	36,180	122,518	108,295
Oil and natural gas operating revenues and expenses per BOE(1)				
Oil and natural gas revenues	$ 87.84	$ 91.98	$ 91.66	$ 93.52
Lease operating expenses	19.49	21.68	19.86	21.55
Marketing expenses, net of third party purchases	1.52	1.04	1.48	1.01

Taxes other than income(4)	5.98	5.88	6.19	6.09
Non-tertiary CO2 revenues and expenses:				
CO2 sales and transportation fees	$ 7,160	$ 6,541	$ 19,256	$ 16,808
CO2 discovery and operating expenses(5)	(1,176)	(1,250)	(8,443)	(4,889)
CO2 revenue and expenses, net	$ 5,984	$ 5,291	$ 10,813	$ 11,919

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

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

(3) Includes ad valorem, production and franchise taxes.

(4) Includes \$0.39, \$0.37, \$0.39 and \$0.34, respectively, of franchise and other taxes not related to our oil and gas producing assets.

(5) Includes \$4.8 million of exploratory drilling costs during the nine months ended September 30, 2012. We incurred no exploratory drilling costs during the three months ended September 30, 2012 nor the three and nine months ended September 30, 2011.

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Total Production

Average daily production by area for each of the four quarters of 2011 and for the first, second, and third quarters of 2012 is shown below:

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2011	Second Quarter 2011	Third Quarter 2011	Fourth Quarter 2011	First Quarter 2012	Second Quarter 2012	Third Quarter 2012
Gulf Coast region:							
Tertiary oil fields	30,825	30,771	31,091	31,144	33,257	35,208	34,786
Non-tertiary fields:							
Mississippi	5,930	5,642	5,636	4,746	4,573	4,095	3,401
Texas	4,371	4,202	4,096	3,868	3,674	4,573	5,173
Louisiana	511	454	47	141	191	189	144
Alabama and other	1,020	1,079	1,064	1,031	1,090	1,117	993
Total Gulf Coast region	42,657	42,148	41,934	40,930	42,785	45,182	44,497
Rocky Mountain region:							
Cedar Creek Anticline	9,163	8,925	8,930	8,858	8,496	8,535	8,490
Bell Creek	890	936	889	840	859	816	777
Other	2,134	2,147	2,204	2,135	2,404	2,314	2,361
Total Rocky Mountain region	12,187	12,008	12,023	11,833	11,759	11,665	11,628
Production excluding properties disposed or to be disposed	54,844	54,156	53,957	52,763	54,544	56,847	56,125
Properties disposed or to be disposed:							
Bakken area assets (1)	6,207	8,172	10,461	12,141	15,226	15,433	16,651
Gulf Coast assets (2)	1,918	1,901	1,732	1,677	1,054	—	—
Paradox assets (3)	635	690	680	653	708	57	—
Total Production	63,604	64,919	66,830	67,234	71,532	72,337	72,776

(1) Includes production from certain Bakken area assets pending sale around the end of November 2012.
(2) Includes production from certain non-core Gulf Coast assets sold in late February 2012.
(3) Includes production from certain non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012.

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Our production (excluding properties disposed or to be disposed) during the three months ended September 30, 2012 increased 4% or 2,168 BOE/d over the 2011 comparable period production levels, and increased from 54,316 BOE/d during the first nine months of 2011 to 55,840 BOE/d during the first nine months of 2012 (a 3% increase). These increases were primarily due to production increases from our tertiary oil fields (see a discussion of our tertiary operations in CO2 Operations above) and the June 2012 acquisition of the Thompson Field, offset by normal declines in most of our other non-tertiary properties. Total production increased 9% between the third quarters of 2011 and 2012, and includes production related to the Bakken area assets (pending sale), certain non-core Gulf Coast assets sold in February 2012 and non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012. On a year-to-date basis, total production increased 11% between the first nine months of 2011 and 2012.

Bakken area production increased 59% and 90% during the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011 primarily due to the acceleration of our drilling activities in the latter half of 2011 in that area. During the latter half of 2011, we operated as many as seven drilling rigs in the Bakken, decreasing to six operated drilling rigs by the end of 2011. We have currently reduced the rig count in the Bakken to four, which has slowed the rate of production growth. During the first nine months of 2012, we completed 31 operated wells in the Bakken which had initial production during the period.

Our production during both the three and nine months ended September 30, 2012 was 93% oil, which remained consistent with oil production of 93% and 92% during the three and nine months ended September 30, 2011, respectively. Excluding Bakken area assets pending sale, our total production during both the three and nine months ended September 30, 2012 was estimated to be 95% oil.

Oil and Natural Gas Revenues

Our oil and natural gas revenues increased 4% and 9% during the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011. The increase in both periods is related to increases in production, partially offset by reductions in commodity prices. Changes in oil and natural gas revenues, excluding any impact of our commodity derivative contracts, are reflected in the following table:

	Three Months Ended September 30, 2012 vs. 2011		Nine Months Ended September 30, 2012 vs. 2011	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase in production	$ 50,317	9%	$ 187,707	11%
Decrease in commodity prices	(27,684)	-5%	(36,723)	-2%
Total increase in oil and natural gas revenues	$ 22,633	4%	$ 150,984	9%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first, second, and third quarters and the nine months ended September 30, 2012 and 2011:

	Three Months Ended March 31,		Three Months Ended June 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
Net Realized Prices:								
Oil price per Bbl	$102.52	$93.67	$95.63	$106.30	$93.09	$96.85	$97.04	$98.95
Natural gas price per Mcf	3.84	4.81	1.87	5.16	3.09	4.95	2.92	4.98
Price per BOE	97.32	88.42	89.96	100.06	87.84	91.98	91.66	93.52
NYMEX Differentials:								
Oil per Bbl	$(0.37)	$(0.59)	$2.14	$3.72	$0.80	$7.25	$0.84	$3.49
Natural gas per Mcf	1.32	0.61	(0.49)	0.78	0.20	0.89	0.33	0.77

As reflected in the table above, our net realized oil prices decreased 4% in the third quarter of 2012 compared to those received during the third quarter of 2011. Company-wide oil price differentials in the third quarter of 2012 were $0.80 per Bbl above NYMEX, compared to an average differential of $7.25 per Bbl above NYMEX in the third quarter of 2011 and $2.14 per Bbl above NYMEX in the second quarter of 2012. The net differential realized by the Company is primarily impacted by positive differentials in the Gulf Coast region, offset by unfavorable differentials in the Rocky Mountain region, each of which is discussed in further detail below.

The Company received favorable NYMEX differentials in the Gulf Coast region during the three and nine months ended September 30, 2012 and 2011, primarily due to the favorable differential for crude oil sold under Light Louisiana Sweet ("LLS") index prices. This LLS-to-NYMEX differential averaged a positive $15.05 per Bbl on a trade-month basis for the third quarter of 2012, compared to a positive $18.90 per Bbl differential in the third quarter of 2011 and a positive $12.55 and $18.14 per Bbl differential in the first and second quarters of 2012. During the third quarter of 2012, the Company sold approximately 39% of its crude oil at prices based on the LLS index price, approximately 22% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. Prices received in a regional market can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. NYMEX pricing, which has long been a benchmark price that reflects the economics in the U.S. midcontinent market, has been influenced in the recent past by significant increases in supply. Alternatively, the LLS market is reflective of market economics in the Gulf Coast region, where both foreign and domestic oil is bought and sold, and correlates more closely to global oil prices. While this differential is significant in the pricing for our oil production, other market and contractual factors may prevent us from realizing the full differential. As indicated by the above variations, the LLS-to-NYMEX differential is volatile and has been at historically high levels in recent periods, which may not continue.

Unfavorable NYMEX differentials in the Rocky Mountain region are largely impacted by oil production from our Bakken area assets which are under contract to be sold. The realized oil prices for these properties averaged $16.34 per Bbl below NYMEX in the third quarter of 2012, compared to an average differential of $5.66 per Bbl below NYMEX in the third quarter of 2011 and $20.08 per Bbl below NYMEX in the second quarter of 2012. Oil in the

Bakken region sold at a significant discount during the first nine months of 2012 due to increased production in the area coupled with limited transportation infrastructure. Transportation infrastructure in the region improved throughout the third quarter of 2012 and we expect our oil differentials there to likewise improve during the fourth quarter of 2012. Excluding these Bakken area assets under contract to be sold, Company-wide differentials were estimated to be $5.43 above NYMEX in the third quarter of 2012, compared to an average differential of $9.59 per Bbl above NYMEX in the third quarter of 2011 and $7.69 above NYMEX in the second quarter of 2012.

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Commodity Derivative Contracts

The following tables summarize the impact our commodity derivative contracts had on our operating results for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,					
	2012	2011	2012	2011	2012	2011
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value gain (loss)	$ (60,726)	$ 205,355	$ (7,174)	$ 229	$ (67,900)	$ 205,584
Cash settlement receipts (payments)	(641)	(1,857)	6,910	6,427	6,269	4,570
Total	$ (61,367)	$ 203,498	$ (264)	$ 6,656	$ (61,631)	$ 210,154

	Nine Months Ended September 30,					
	2012	2011	2012	2011	2012	2011
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value gain (loss)	$ 37,752	$ 225,485	$ (17,910)	$ (8,393)	$ 19,842	$ 217,092
Cash settlement receipts (payments)	(9,580)	(23,857)	21,941	19,073	12,361	(4,784)
Total	$ 28,172	$ 201,628	$ 4,031	$ 10,680	$ 32,203	$ 212,308

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 5 and 6 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

During the third quarter of 2012, we restructured most of our oil derivative collar contracts in the first three quarters of 2013 to increase the weighted average floor price to approximately $80 per Bbl and decrease the weighted average ceiling price. See Note 5 to the Unaudited Condensed Consolidated Financial Statements for a summary of our current derivative positions.

Production Expenses

Lease operating expenses during the three months ended September 30, 2012 of $130.5 million decreased $2.8 million (2%) compared to lease operating expenses in the same period in 2011, which change consisted of a 6% increase in operating expense of our tertiary oil properties offset by an 11% decrease in non-tertiary operating expense. Lease operating expense during the nine months ended September 30, 2012 of $393.0 million increased $9.8 million (3%) compared to lease operating expenses in the same period in 2011, consisting of a 12% increase in our tertiary operating expense offset by a 9% decrease in non-tertiary operating expense. See discussion of tertiary operating expenses above under CO2 Operations. The decrease in non-tertiary operating expense during both comparable periods is primarily due to the divestiture of certain non-core assets located in central and southern Mississippi, southern Louisiana, and in the Paradox Basin of Utah during the first and second quarters of 2012, offset by incremental lease operating expense related to our acquisition of Thompson Field during the second quarter of 2012.

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Lease operating expense averaged $19.49 and $19.86 per BOE for the three and nine months ended September 30, 2012, a decrease of 10% and 8% compared to $21.68 and $21.55 per BOE, respectively, for the same periods in 2011. The lower operating expenses per BOE during both comparative periods were largely driven by our non-tertiary properties and are primarily due to increased production related to our Bakken area assets under contract to be sold, which have lower operating costs than our other properties, and the sale of certain non-core assets during the first half of 2012, which had a higher operating cost per BOE compared to the average of our other properties. Our tertiary operating costs, which have historically been higher than our Company-wide operating costs, averaged $23.50 and $24.35 per Bbl during the three and nine months ended September 30, 2012, respectively, compared to $24.91 and $24.24 per Bbl for the same periods in 2011. See CO2 Operations for a more detailed discussion of our tertiary operating costs. Excluding lease operating expenses for the Bakken area assets pending sale, lease operating expenses were estimated to be $23.79 and $23.99 per BOE for the three and nine months ended September 30, 2012, compared to $24.88 and $23.86 per BOE, respectively, for the same periods in 2011.

Taxes other than income, which includes ad valorem, production and franchise taxes, averaged $5.98 and $6.19 per BOE for the three and nine months ended September 30, 2012, which remained consistent with $5.88 and $6.09 per BOE for the same periods in 2011. Excluding Bakken area assets pending sale, taxes other than income were estimated to be $5.67 and $5.94 per BOE for the three and nine months ended September 30, 2012, compared to $5.51 and $5.84 per BOE in the same periods in 2011.

General and Administrative Expenses ("G&A")

In thousands, except per BOE data and employees	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Administrative costs	$ 76,192	$ 56,661	$ 221,991	$ 183,605
Stock-based compensation	9,247	11,154	29,205	32,178
Operator labor and overhead recovery charges	(34,659)	(32,166)	(104,665)	(92,859)
Capitalized exploration and development costs	(12,582)	(9,036)	(36,900)	(25,283)
Net G&A expense	$ 38,198	$ 26,613	$ 109,631	$ 97,641
G&A per BOE:				
Administrative costs, net	$ 4.70	$ 2.88	$ 4.50	$ 4.07
Stock-based compensation, net	1.01	1.45	1.04	1.42
Net G&A expense	$ 5.71	$ 4.33	$ 5.54	$ 5.49
Employees as of September 30	1,423	1,274		

Net G&A expense during the three and nine months ended September 30, 2012 increased on both an absolute dollar and per BOE basis compared to levels in the same periods in 2011, as the increases in administrative costs exceeded the increase in operator labor and overhead recovery charges and capitalized exploration and developments costs. The 32% and 1% increase in net G&A expense per BOE between the two periods was further impacted by higher production.

Administrative costs increased $19.5 million (34%) and $38.4 million (21%) during the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011. The increase between the comparative three and nine month periods was primarily due to higher compensation-related costs resulting both from an increase in headcount (12%) and salaries, and lower bonus expense in the prior year periods caused by a reduction in our accrued employee bonuses during the three months ended September 30, 2011, partially offset by additional compensation in the 2011 periods related to the resignation of an officer. Gross stock-based compensation was also higher in the 2011 periods, due in part to the resignation of the officer's position.

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Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells and drilling activities, additional tertiary operations and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 8% and 13% during the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE data and interest rates	2012	2011	2012	2011
Cash interest expense	$ 53,569	$ 51,540	$ 161,978	$ 156,255
Non-cash interest expense	3,695	3,930	11,124	14,392
Less: capitalized interest	(19,437)	(17,853)	(57,357)	(42,004)
Interest expense	$ 37,827	$ 37,617	$ 115,745	$ 128,643
Interest income and other income	$ 5,055	$ 4,441	$ 14,214	$ 12,445
Net cash interest expense and other income per BOE (1)	$ 4.34	$ 4.80	$ 4.57	$ 5.79
Average debt outstanding	$ 3,073,450	$ 2,426,820	$ 2,874,146	$ 2,415,193
Average interest rate (2)	7.0 %	8.5 %	7.5 %	8.6 %

(1) Cash interest expense less capitalized interest less interest and other income on BOE basis.
(2) Includes commitment fees but excludes debt issue costs and amortization of discount and premium.

Cash interest expense increased $2.0 million (4%) and $5.7 million (4%) during the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011. The reduction in the average interest rate is primarily a result of increased borrowings under our bank credit facility, which carries rates lower than that of our senior subordinated notes. The increase in capitalized interest between the three and nine months ended September 30, 2011 and 2012 relates primarily to incremental capitalized interest on the Riley Ridge plant and Greencore pipeline construction projects.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE data	2012	2011	2012	2011
Depletion and depreciation of oil and natural gas properties	$ 112,617	$ 90,241	$ 328,952	$ 264,288
Depletion and depreciation of CO2 properties	5,829	4,625	16,365	13,803
Asset retirement obligations	1,992	1,456	5,516	4,715
Depreciation of other fixed assets	16,497	5,656	39,286	16,261

Total DD&A	$ 136,935	$ 101,978	$ 390,119	$ 299,067
DD&A per BOE:				
Oil and natural gas properties	$ 17.12	$ 14.91	$ 16.90	$ 15.13
CO2 and other fixed assets	3.33	1.68	2.82	1.69
Total DD&A cost per BOE	$ 20.45	$ 16.59	$ 19.72	$ 16.82

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. During the first nine months of 2012, we added estimated proved reserves of 42.6 MMBOE at Hastings Field, 12.0 MMBOE in the Bakken and 12.3 MMBOE associated with our acquisition of Thompson Field. These additions were offset by a 12.7 MMBOE reduction in estimated proved reserves due to the sale of certain non-core assets in central and southern Mississippi and southern Louisiana and in the Paradox Basin of Utah. In conjunction with the recognition of proved reserves at Hastings Field, we transferred $222.5 million from Unevaluated Properties to Proved properties on our Unaudited Condensed Consolidated Balance Sheet.

Depletion and depreciation of oil and natural gas properties increased 25% and 24% on an absolute-dollar basis for the three and nine months ended September 30, 2012, respectively, and 15% and 12% on a per-BOE basis during the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011, primarily due to higher finding costs per barrel and upward revisions in estimated future development costs associated with the Bakken capital program. The increase in DD&A on an absolute-dollar basis was further impacted by increases in production volumes. On a sequential quarterly basis, DD&A per BOE for oil and natural gas properties remained relatively stable, increasing only 1%. We expect DD&A cost per BOE to decrease prospectively after the Pending Exchange Transaction is closed due to the reduction in capitalized costs subject to depletion. Upon closing of the Pending Exchange Transaction, the majority of the proceeds received in the sale of the Bakken area assets would be recorded as a reduction to the full cost pool as we do not expect to record a gain or loss for financial statement purposes on the sale of the Bakken area assets in accordance with the full cost method of accounting.

The increase in depreciation of other fixed assets is primarily due to incremental pipeline depreciation and the change in classification of our equipment leases from operating to capital during the second quarter of 2012.

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 September 30, 2012; however, if oil and natural gas prices were to decrease significantly in subsequent periods, we may be required to record write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend, in part, upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, as well as additional capital spent.

Impairment of Assets

We recognized $17.5 million of impairment charges during the nine months ended September 30, 2012, primarily related to our investment in Faustina Hydrogen Products LLC, an entity created to develop a proposed plant from which we would offtake CO2. See Note 6, Fair Value Measurements, to the Unaudited Condensed Consolidated Financial Statements.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE amounts and tax rates	2012	2011	2012	2011
Current income tax expense (benefit)	$4,342	$(5,331)	$33,834	$5,849
Deferred income tax expense	49,670	172,981	216,959	317,601
Total income tax expense	$54,012	$167,650	$250,793	$323,450
Average income tax expense per BOE	$8.07	$27.27	$12.67	$18.19

Effective tax rate	38.8 %	37.8 %	37.9 %	38.3 %

Our income taxes are based on an estimated statutory rate of approximately 38%. Our effective tax rate for the third quarter of 2012 was slightly higher compared to our statutory rate, primarily due to the recognition of additional tax expense in our 2011 tax returns in excess of estimated expense included in our tax provision at December 31, 2011.

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As of September 30, 2012, after finalization of our 2011 tax return, we had an estimated $61.4 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $36.9 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2012 or future years, but cannot be used to offset alternative minimum tax. The enhanced oil recovery credits do not begin to expire until 2022. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we do not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

Per BOE Data

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

Per BOE data	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Oil and natural gas revenues	$87.84	$91.98	$91.66	$93.52
Gain on settlements of derivative contracts	0.93	0.74	0.63	(0.27)
Lease operating expenses	(19.49)	(21.68)	(19.86)	(21.55)
Production and ad valorem taxes	(5.59)	(5.51)	(5.80)	(5.75)
Marketing expenses, net of third party purchases	(1.52)	(1.04)	(1.48)	(1.01)
Production netback	62.17	64.49	65.15	64.94
CO2 sales, net of operating expenses	0.89	0.86	0.54	0.67
General and administrative expenses	(5.71)	(4.33)	(5.54)	(5.49)
Net cash interest expense and other income	(4.34)	(4.80)	(4.57)	(5.79)
Other	(0.70)	1.96	(1.79)	0.38
Changes in assets and liabilities relating to operations	(8.47)	(6.83)	(1.93)	(7.52)
Cash flow from operations	43.84	51.35	51.86	47.19
DD&A	(20.45)	(16.59)	(19.72)	(16.82)
Deferred income taxes	(7.42)	(28.13)	(10.96)	(17.86)
Loss on early extinguishment of debt	—	—	—	(0.91)
Non-cash commodity derivative adjustments	(10.13)	33.44	1.00	12.21
Impairment of assets	—	—	(0.89)	—
Other non-cash items	6.91	4.77	(0.53)	5.48
Net income	$12.75	$44.84	$20.76	$29.29

Critical Accounting Policies

For additional discussion of our critical accounting policies, which remain unchanged, see Management's Discussion and Analysis of Financial Condition and Results of Operations in the Form 10-K.

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

Forward-Looking Information

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted cash flows and capital expenditures, drilling activity or methods including the timing and location thereof, pending or planned acquisitions or dispositions, development activities, timing of CO_2 injections and initial production responses thereto, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves, helium reserves, potential reserves, percentages of recoverable original oil in place, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, cost and availability of equipment and services, liquidity, availability of capital, borrowing capacity, regulatory matters, prospective legislation affecting the oil and gas industry, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics and other variables surrounding our operations and future plans. Such forward-looking statements generally are accompanied by words such as “plan,” “estimate,” “expect,” “predict,” “anticipate,” “projected,” “should,” “assume,” “believe,” “may,” or other words that convey, or are intended to convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management’s current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and the Company’s financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil and/or natural gas prices and consequently in the prices received or demand for the Company’s oil and natural gas; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results; operating hazards; disruption of operations and damages from hurricanes, tropical storms, or forest fires; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial and credit markets; general economic conditions; competition; government regulations, including tax and environmental; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company’s other public reports, filings and public statements including, without limitation, the Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Long-term Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable-rate debt. Our bank credit agreement and our senior subordinated notes do not have any triggers or covenants regarding our debt ratings with rating agencies. Borrowings on our bank credit facility, which bear interest at variable rates, expose us to market risk related to changes in interest rates. As of September 30, 2012, our borrowings on our bank credit facility were $625.0 million, with a weighted average interest rate of 2.0%. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense.

The following table presents the principal balances of our debt, by maturity date, as of September 30, 2012:

In thousands, except percentages	2014	2015	2016	2017	2020	2021
Variable rate debt:						
Bank Credit Facility (weighted average interest rate of 2.00% at September 30, 2012)	$ —	$ —	$ 625,000	$ —	$ —	$ —
Fixed rate debt:						
9½% Senior Subordinated Notes due 2016	—	—	224,920	—	—	—
9¾% Senior Subordinated Notes due 2016	—	—	426,350	—	—	—
8¼% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—
6 % Senior Subordinated Notes due 2021	—	—	—	—	—	400,000
Other Subordinated Notes	1,072	485	—	2,250	—	—

Commodity Derivative Contracts and Commodity Price Sensitivity

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year, depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production approximately 12 to 18 months in the future from the current quarter, as we believe it is important to protect our future cash flow for a short period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times. See Notes 5 and 6 to the

Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. We only enter into commodity derivative contracts with parties that are lenders under our bank credit 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 September 30, 2012, our commodity derivative contracts were recorded at their fair value, which was a net asset of approximately $26.0 million (excluding $0.7 million of deferred premiums that we are obligated to pay for our derivative contracts, which payments are not subject to changes in commodity prices), a change of approximately $19.9 million from the $6.1 million fair value net asset recorded at December 31, 2011 (excluding $4.1 million of deferred premiums). This change is primarily related to changes in oil futures prices between December 31, 2011 and September 30, 2012.

Based on NYMEX crude oil and natural gas futures prices as of September 30, 2012, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as seen in the following table:

	Receipt / (Payment)	
In thousands	Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
NYMEX futures prices as of September 30, 2012	$ (664)	$ 6,073
10% increase in prices	(1,393)	5,478
10% decrease in prices	(131)	6,665

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2012, to ensure that information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

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

Denbury Resources Inc.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information with respect to legal proceedings is incorporated by reference from the Form 10-K.

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference from Item 1A of the Form 10-K. There have been no material changes to the risk factors since the filing of the Form 10-K.

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

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the third quarter of 2012:

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 (in millions)
July 2012	4,378	$ 14.62	—	$ —
August 2012	15,468	15.63	—	—
September 2012	2,503,765	16.48	2,493,435	263.7 (1)
Total	2,523,611	16.47	2,493,435	$ 263.7

(1) Amounts shown do not give effect to the repurchase of an additional 2,133,910 shares of Denbury common stock in October 2012 under the share repurchase program for $34.9 million, or $16.35 per share. From the time the $500 million share repurchase program commenced in October 2011 through October 2012, we have purchased a total of $271.2 million of common stock under the program, and thus are authorized to spend an additional $228.8 million under this repurchase program.

Other than purchases made under our stock repurchase program, all other stock purchases during the third quarter of 2012 were made in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights.

Item 3. Defaults upon Senior Securities

None

Item 4. Mine Safety Disclosures

None

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Item 5. Other Information

On November 2, 2012, we entered into the Ninth Amendment to the Bank Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the “Ninth Amendment”) pursuant to which certain provisions of the Bank Credit Agreement were amended to, among other things (i) permit the sale of the Bakken area assets, and (ii) increase the amount of distributions Denbury may make to its equity holders, including the repurchase of our common stock and/or the making of cash dividends with respect thereto, from an aggregate amount of $500 million up to an aggregate amount of $1.2 billion during the term of the Bank Credit Agreement, subject, in the case of such distributions, to certain existing restrictions and conditions, including the absence of any default or borrowing base deficiency, availability of no less than 25% of the borrowing base and compliance with all financial covenants, in each case on a pro forma basis after giving effect to any such distribution. The Ninth Amendment also provided a limited waiver of any oil hedging noncompliance that may occur as a result of the Pending Exchange Transaction during the period commencing on the closing date of the Pending Exchange Transaction and continuing through and including December 31, 2013.

The foregoing description is qualified in its entirety by reference to the full text of the Ninth Amendment, which is attached as Exhibit 10(a) to this Quarterly Report on Form 10-Q and incorporated herein by reference.

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Denbury Resources Inc.

Item 6. Exhibits

Exhibit	Description
2(a)	Exchange Agreement by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation dated as of September 19, 2012 (incorporated by reference from Exhibit 2.1 of our Form 8-K filed on September 25, 2012).
3(a)*	Second Restated Certificate of Incorporation of Denbury Resources Inc.
3(b)	Amended and Restated Bylaws of Denbury Resources Inc. (incorporated by reference from Exhibit 3.2 of our Form 8-K filed on May 21, 2012).
10(a)*	Ninth Amendment to Credit Agreement dated as of March 9, 2010, dated as of November 2, 2012, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

* Included herewith.

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SIGNATURES

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

DENBURY RESOURCES INC.

Date: November 8, 2012	/s/ Mark C. Allen Mark C. Allen Senior Vice President and Chief Financial Officer
Date: November 8, 2012	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

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