DENBURY RESOURCES INC
Form 10-Q
November 07, 2013

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, 2013

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

For the transition period from _______ to ________

Commission file number: 001-12935

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

Delaware	20-0467835
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
5320 Legacy Drive, Plano, TX	75024
(Address of principal executive offices)	(Zip Code)
Registrant's telephone number, including area code:	(972) 673-2000

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

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

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

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

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

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

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

Class	Outstanding at October 31, 2013
Common Stock, $.001 par value	366,689,106

Denbury Resources Inc.

Table of Contents

Table of Contents

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, 2013	December 31, 2012
Assets		
Current assets		
Cash and cash equivalents	$26,548	$98,511
Restricted cash	—	1,050,015
Accrued production receivable	281,872	253,131
Trade and other receivables, net	83,904	81,971
Derivative assets	167	19,477
Deferred tax assets	34,422	29,156
Other current assets	12,881	10,493
Total current assets	439,794	1,542,754
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	8,314,196	6,963,211
Unevaluated	1,177,564	809,154
CO_2 properties	1,094,699	1,032,653
Pipelines and plants	2,154,186	2,035,126
Other property and equipment	434,113	417,207
Less accumulated depletion, depreciation, amortization and impairment	(3,531,811)	(3,180,241)
Net property and equipment	9,642,947	8,077,110
Derivative assets	2,970	36
Goodwill	1,283,590	1,283,590
Other assets	240,344	235,852
Total assets	$11,609,645	$11,139,342
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$334,850	$414,668
Oil and gas production payable	193,056	161,945
Derivative liabilities	40,261	2,842
Current maturities of long-term debt	35,581	36,966
Total current liabilities	603,748	616,421
Long-term liabilities		
Long-term debt, net of current portion	3,238,969	3,104,462
Asset retirement obligations	123,994	102,730
Derivative liabilities	16,013	23,781
Deferred tax liabilities	2,328,131	2,153,452
Other liabilities	25,962	23,607
Total long-term liabilities	5,733,069	5,408,032
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; 408,779,349 and 406,163,194 shares issued, respectively	409	406
Paid-in capital in excess of par	3,173,394	3,136,461
Retained earnings	2,754,440	2,434,835
Accumulated other comprehensive loss	(294)	(348)
Treasury stock, at cost, 42,115,224 and 30,601,262 shares, respectively	(655,121)	(456,465)
Total stockholders' equity	5,272,828	5,114,889
Total liabilities and stockholders' equity	$11,609,645	$11,139,342

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Operations
(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues and other income				
Oil, natural gas, and related product sales	$666,803	$588,156	$1,878,644	$1,813,798
CO_2 sales and transportation fees	6,739	7,160	19,859	19,256
Interest income and other income	11,293	5,055	19,502	14,214
Total revenues and other income	684,835	600,371	1,918,005	1,847,268
Expenses				
Lease operating expenses	180,967	130,485	542,067	392,960
Marketing expenses	13,131	14,728	36,259	37,776
CO_2 discovery and operating expenses	4,120	1,176	11,261	8,443
Taxes other than income	49,267	40,012	132,218	122,518
General and administrative expenses	35,969	38,198	111,240	109,631
Interest, net of amounts capitalized of $19,768, $19,437, $64,752, and $57,357, respectively	34,501	37,827	101,137	115,745
Depletion, depreciation, and amortization	125,595	136,935	365,400	390,119
Derivatives expense (income)	80,446	61,631	46,874	(32,203)
Loss on early extinguishment of debt	—	—	44,651	—
Impairment of assets	—	—	—	17,515
Other expenses	1,474	—	14,292	23,272
Total expenses	525,470	460,992	1,405,399	1,185,776
Income before income taxes	159,365	139,379	512,606	661,492
Income tax provision	57,311	54,012	193,001	250,793
Net income	$102,054	$85,367	$319,605	$410,699
Net income per common share				
Basic	$0.28	$0.22	$0.87	$1.06
Diluted	$0.28	$0.22	$0.86	$1.05
Weighted average common shares outstanding				
Basic	366,088	387,512	368,101	387,015
Diluted	369,142	390,909	371,316	390,854

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Comprehensive Operations
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income	$102,054	$85,367	$319,605	$410,699
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $11, $11, $30, and $32, respectively	17	17	54	52
Total other comprehensive income	17	17	54	52
Comprehensive income	$102,071	$85,384	$319,659	$410,751

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.
Unaudited Condensed Consolidated Statements of Cash Flows
(In thousands)

	Nine Months Ended September 30,	
	2013	2012
Cash flow from operating activities:		
Net income	$319,605	$410,699
Adjustments to reconcile net income to cash flow from operating activities:		
Depletion, depreciation, and amortization	365,400	390,119
Deferred income taxes	169,634	216,959
Stock-based compensation	23,774	22,662
Noncash fair value derivative adjustments	46,296	(19,757)
Loss on early extinguishment of debt	44,651	—
Amortization of debt issuance costs and discounts	10,581	11,021
Impairment of assets	—	17,515
Other, net	(3,570)	15,087
Changes in assets and liabilities, net of effects from acquisitions:		
Accrued production receivable	(34,910)	3,221
Trade and other receivables	(756)	11,010
Other current and long-term assets	(1,199)	8,218
Accounts payable and accrued liabilities	52,672	(30,127)
Oil and natural gas production payable	31,111	5,014
Other liabilities	(11,080)	(35,515)
Net cash provided by operating activities	1,012,209	1,026,126
Cash flow used in investing activities:		
Oil and natural gas capital expenditures	(688,270)	(848,618)
Acquisitions of oil and natural gas properties	(1,896)	(155,636)
Bakken exchange transaction	(10,385)	—
CO_2 capital expenditures	(72,929)	(93,945)
Pipelines and plants capital expenditures	(136,654)	(231,459)
Purchases of other assets	(29,680)	(18,666)
Net proceeds from sales of oil and natural gas properties and equipment	6,312	33,973
Proceeds from sale of short-term investments	—	83,545
Other	(18,201)	(7,166)
Net cash used in investing activities	(951,703)	(1,237,972)
Cash flow provided by (used in) financing activities:		
Bank repayments	(1,170,000)	(970,000)
Bank borrowings	780,000	1,210,000
Repayment of senior subordinated notes	(651,270)	—
Premium paid on repayment of senior subordinated notes	(36,475)	—
Proceeds from issuance of senior subordinated notes	1,200,000	—
Costs of debt financing	(20,026)	(17)
Common stock repurchase program	(215,197)	(16,747)
Other	(19,501)	(6,049)
Net cash provided by (used in) financing activities	(132,469)	217,187
Net increase (decrease) in cash and cash equivalents	(71,963)	5,341

Cash and cash equivalents at beginning of period	98,511	18,693
Cash and cash equivalents at end of period	$26,548	$24,034

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents
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 CO_2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to tertiary recovery operations.

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2012 (the "Form 10-K"). Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company," or "Denbury," refer to Denbury Resources Inc. and its subsidiaries.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end, and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of September 30, 2013, our consolidated results of operations for the three and nine months ended September 30, 2013 and 2012, and our consolidated cash flows for the nine months ended September 30, 2013 and 2012.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

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 impact of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights ("SARs"), nonvested restricted stock and nonvested performance-based equity awards. For the three and nine months ended September 30, 2013 and 2012, there were no adjustments to net income for purposes of calculating basic or diluted net income per common share.

The following is a reconciliation of the weighted average shares outstanding 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	2013	2012	2013	2012
Basic weighted average common shares outstanding	366,088	387,512	368,101	387,015
Potentially dilutive securities:				
Restricted stock, stock options, SARs and performance-based equity awards	3,054	3,397	3,215	3,839
Diluted weighted average common shares outstanding	369,142	390,909	371,316	390,854

Basic weighted average common shares excludes shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares, 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. Stock options and SARs of 3.6 million shares for the three and nine months ended September 30, 2013, and 5.4 million and 4.1 million shares for the three and nine months ended September 30, 2012, respectively, were not included in the computation of diluted net income per share as their effect would have been antidilutive.

Recent Accounting Pronouncements

Balance Sheet-Offsetting Assets and Liabilities. In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-11, Disclosure about Offsetting Assets and Liabilities (“ASU 2011-11”). ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities ("ASU 2013-01"). The update clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with the Derivatives and Hedging topic of the Financial Accounting Standards Board Codification ("FASC"), including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. ASU 2011-11 and ASU 2013-01 became effective for our fiscal year beginning January 1, 2013 and have been applied retrospectively for all comparative periods presented. The adoption of ASU 2011-11 and ASU 2013-01 did not affect our consolidated financial statements, but required additional disclosures in the notes thereto.

Note 2. Acquisitions and Divestitures

Fair Value. 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 intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The fair value of oil and natural gas properties is based on significant inputs not observable in the market, which the FASC Fair Value Measurements and Disclosures topic defines as Level 3 inputs. Key assumptions may include: (1) NYMEX oil and natural gas futures (this input is observable); (2) dollar-per-acre values of recent sale transactions (this input is observable); (3) projections of the estimated quantities of oil and natural gas reserves, including those classified as proved, probable and possible; (4) estimated oil and natural gas pricing differentials; (5) projections of future rates of production; (6) timing and amount of future development and operating costs; (7) projected costs of CO_2 (to a market participant); (8) projected reserve recovery factors; and (9) risk-adjusted discount rates.

2013 Acquisition

Cedar Creek Anticline Acquisition. In January 2013, we entered into an agreement to acquire producing assets in the Cedar Creek Anticline ("CCA") of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips

Company ("ConocoPhillips") for $1.05 billion ($1.0 billion after final closing adjustments primarily for revenues and costs of the purchased properties from the January 1, 2013 effective date to the closing date). We closed the acquisition on March 27, 2013. We funded the acquisition with a portion of the cash proceeds from the Bakken Exchange Transaction (described below). This acquisition meets the definition of a business under the FASC Business Combinations topic. As such, we estimated the fair value of assets acquired and liabilities assumed as of the closing date of the acquisition, using a discounted future net cash flow model.

The fair value of the assets acquired and liabilities assumed was finalized during the third quarter of 2013, after consideration of final closing adjustments, evaluation of oil and natural gas properties, other assets and related asset retirement obligations. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the CCA acquisition:

In thousands	
Consideration:	
Cash consideration [1]	$1,001,707
Fair value of assets acquired and liabilities assumed:	
Oil and natural gas properties	
Proved	783,507
Unevaluated	222,820
Other assets	2,589
Asset retirement obligations	(7,209)
	$1,001,707

(1) $989.0 million of this cash consideration was paid through a qualified intermediary from cash placed in qualifying trust accounts from a portion of the proceeds received from the Bakken Exchange Transaction (as defined below) in order to enable a like-kind-exchange transaction for federal income tax purposes. As such, this amount is not reflected as a cash payment to purchase oil and natural gas properties in our Unaudited Condensed Consolidated Statement of Cash Flows.

For the three months ended September 30, 2013 and for the period from March 27, 2013 to September 30, 2013, we recognized $97.1 million and $189.8 million of oil, natural gas, and related product sales, respectively, from the property interests acquired in the CCA acquisition. For the three months ended September 30, 2013 and for the period from March 27, 2013 to September 30, 2013, we recognized $70.9 million and $138.8 million of net field operating income (defined as oil, natural gas and related product sales less lease operating expenses, production and ad valorem taxes, and marketing expenses), respectively, related to the CCA acquisition.

2012 Acquisitions and Divestitures

Bakken Exchange Transaction. In late 2012, we closed a sale and exchange transaction (the "Bakken Exchange Transaction") with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, “ExxonMobil”) in which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash (after closing adjustments), (2) ExxonMobil's operating interests in Webster Field in Texas and Hartzog Draw Field in Wyoming, and (3) approximately a one-third overriding royalty ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming.

This acquisition meets the definition of a business under the FASC Business Combinations topic. The fair value of the assets acquired and liabilities assumed was finalized during the third quarter of 2013, after consideration of final closing adjustments and evaluation of reserves. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the Bakken Exchange Transaction:

In thousands	
Consideration:	
Fair value of net assets transferred	$1,866,107
Fair value of assets acquired and liabilities assumed:	
Cash	1,277,041
Oil and natural gas properties	
Proved	182,289
Unevaluated	90,690
CO_2 properties	314,505
Other property and equipment	23,424
Other assets	477
Other liabilities	(8,528)
Asset retirement obligations	(13,791)
	$1,866,107

Thompson Field Acquisition. In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after closing adjustments. The field is located in close proximity to Hastings Field, which is an enhanced oil recovery field that we are currently flooding with CO_2 and which is the current terminus of the Green Pipeline which transports CO_2 both from the Jackson Dome area, located near Jackson, Mississippi, and from various anthropogenic sources along the route of the pipeline. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also a planned future tertiary field. 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 CO_2 injection.

This acquisition meets the definition of a business under the FASC Business Combinations topic. The fair values assigned to assets acquired and liabilities assumed in this 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, 2012.

Unaudited Pro Forma Acquisition Information. The following combined pro forma total revenues and other income and net income are presented as if the CCA Acquisition, Bakken Exchange Transaction and Thompson Field acquisition had occurred on January 1, 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share data	2013	2012	2013	2012
Pro forma total revenues and other income	$684,835	$598,340	$2,000,179	$1,925,385
Pro forma net income	102,054	92,857	347,624	461,009
Pro forma net income per common share				
Basic	$0.28	$0.24	$0.94	$1.19
Diluted	0.28	0.24	0.94	1.18

Other 2012 Divestitures. 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 final closing adjustments totaled $68.5 million. In February 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for net proceeds of $141.8 million, after final closing adjustments. The sale had an effective date of December 1, 2011. We did not record a gain or loss on these divestitures in accordance with the full cost method of accounting.

Note 3. Long-Term Debt

The following long-term debt and capital lease obligations were outstanding as of the dates indicated:

In thousands	September 30, 2013	December 31, 2012
Bank Credit Agreement	$310,000	$700,000
9½% Senior Subordinated Notes due 2016, including premium of $9,118	—	234,038
9¾% Senior Subordinated Notes due 2016, including discount of $13,569	—	412,781
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 3/8% Senior Subordinated Notes due 2021	400,000	400,000
4 5/8% Senior Subordinated Notes due 2023	1,200,000	—
Other Subordinated Notes, including premium of $19 and $25, respectively	3,826	3,832
Pipeline financings	229,619	236,244
Capital lease obligations	134,832	158,260
Total	3,274,550	3,141,428
Less: current obligations	(35,581)	(36,966)
Long-term debt and capital lease obligations	$3,238,969	$3,104,462

The ultimate parent company in our corporate structure, Denbury Resources Inc. (“DRI”), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the guarantees of the notes are full and unconditional and joint and several.

4 5/8% Senior Subordinated Notes due 2023

In February 2013, we issued $1.2 billion of 4 5/8% Senior Subordinated Notes due 2023 (the “2023 Notes”). The 2023 Notes, which carry a coupon rate of 4.625%, were sold at par. The net proceeds, after issuance costs, of approximately $1.18 billion were used to repurchase or redeem a portion of our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes"), all of our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") (see Repurchase and Redemption of 9½% Notes and 9¾% Notes below) and to pay down a portion of outstanding borrowings on our Bank Credit Facility (as defined below).

The 2023 Notes mature on July 15, 2023, and interest is payable on January 15 and July 15 of each year, commencing July 15, 2013. We may redeem the 2023 Notes in whole or in part at our option beginning January 15, 2018, at the following redemption prices: 102.313% on or after January 15, 2018; 101.542% on or after January 15, 2019; 100.771% on or after January 15, 2020; and 100% on or after January 15, 2021. Prior to January 15, 2016, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2023 Notes at a redemption price of 104.625% with the proceeds of certain equity offerings. In addition, at any time prior to January 15, 2018, we may redeem 100% of the principal amount of the 2023 Notes at a redemption price equal to 100% of the principal amount plus a “make whole” premium and accrued and unpaid interest. The indenture for the 2023 Notes (the "2023 Indenture") contains certain restrictions on our ability to take or permit certain actions, including restrictions on our ability to: (1) incur additional debt; (2) pay dividends on our common stock or redeem, repurchase or retire such stock or subordinated debt unless certain leverage ratios are met; (3) make investments; (4) create liens on our assets; (5) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (6) engage in transactions with our affiliates; (7) transfer or sell assets; and (8) consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries. Although the covenants contained in our other senior subordinated notes indentures are generally consistent with those contained in our 2023 Indenture, the 2023 Indenture covenants permit us in certain circumstances to make restricted payments exceeding the amount allowed under our other senior subordinated notes indentures. Under the 2023 Indenture, these restricted payments, which include share repurchases and dividend payments, do not reduce our restricted payment limitation, provided we maintain (both before and after giving effect to any such payment) a predefined leverage ratio of at least 2.5 to 1. The leverage ratio represents the ratio of total debt to EBITDA, both as defined within the 2023 Indenture.

Repurchase and Redemption of 9½% Notes and 9¾% Notes

On January 22, 2013, we commenced cash tender offers to purchase the outstanding $426.4 million principal amount of our 9¾% Notes at 105.425% of par and the outstanding $224.9 million principal amount of our 9½% Notes at 106.869% of par. During February 2013, we accepted for purchase $191.7 million principal amount of the outstanding 9¾% Notes and $186.7 million principal amount of the outstanding 9½% Notes. We received sufficient consents in the solicitation to amend the indenture governing the 9½% Notes to eliminate most of the restrictive covenants and certain events of default. The purchases under these tender offers were funded by a portion of the proceeds received from the issuance of our 2023 Notes. The tender offers expired on February 19, 2013.

On February 5, 2013, we issued a notice of redemption for the remaining $234.7 million principal amount outstanding of our 9¾% Notes at 104.875% of par, and on March 7, 2013, we repurchased all of the remaining 9¾% Notes outstanding. On March 28, 2013, we issued a notice of redemption for the remaining $38.2 million principal amount outstanding of our 9½% Notes at 104.75% of par, and on May 1, 2013, we repurchased all of the remaining 9½% Notes outstanding.

We recognized a loss associated with the debt repurchases of $44.7 million during the nine months ended September 30, 2013, consisting of both premium payments made to repurchase or redeem the 9¾% Notes and 9½% Notes and the elimination of unamortized debt issuance costs, discounts and premiums related to these notes. The loss is included in our Unaudited Condensed Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt".

$1.6 Billion Revolving Credit Agreement

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders 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 and upon requested special redeterminations. The borrowing base is adjusted at the banks' discretion and is based in part upon external factors over which we have no control. If the borrowing base were to be less than outstanding borrowings under the Bank Credit Agreement, we would be required to repay the deficit over a period not to exceed four months. As part of the semi-annual review completed in late October 2013 pursuant to the terms of the Bank Credit Agreement, our borrowing base was reaffirmed at $1.6 billion. Our next semi-annual redetermination is scheduled to occur on or around May 1, 2014. The weighted average interest rate on borrowings under this revolving credit facility, evidenced by the Bank Credit Agreement (the "Bank Credit Facility") was 1.7% as of September 30, 2013. 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. Loans under the Bank Credit Facility mature in May 2016.

Note 4. Share Repurchase Program

Under our board-authorized share repurchase program, we repurchased 6.7 million shares of Denbury common stock for $114.8 million during the three months ended September 30, 2013 and 11.7 million shares of Denbury common stock for $200.0 million during the nine months ended September 30, 2013. Since commencement of the share repurchase program in October 2011 through September 30, 2013, we have repurchased a total of 42.8 million shares of Denbury common stock for $661.9 million, or $15.48 per share. As of September 30, 2013, we had $109.3 million of remaining repurchases authorized under our share repurchase program.

Table of Contents
Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Note 5. Derivative Instruments

Oil and Natural Gas Derivative Contracts

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.

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, costless collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted oil production approximately two years in the future from the current quarter, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of continuing worldwide economic uncertainties and commodity price volatility. Because our current and foreseeable production is primarily oil, we currently use only oil derivative contracts in our commodity market risk management program, and have no natural gas derivative contracts for 2013 or beyond.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2013	2012	2013	2012
Oil				
Cash payment on settlements of derivative contracts	$662	$641	$662	$9,580
Noncash fair value adjustments to derivative contracts – expense (income)	79,784	60,726	46,212	(37,752)
Total derivatives expense (income) – oil	80,446	61,367	46,874	(28,172)
Natural Gas				
Cash receipt on settlements of derivative contracts	—	(6,910)	—	(21,941)
Noncash fair value adjustments to derivative contracts – expense	—	7,174	—	17,910
Total derivatives expense (income) – natural gas	—	264	—	(4,031)
Derivatives expense (income)	$80,446	$61,631	$46,874	$(32,203)

Table of Contents
Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Commodity Derivative Contracts Not Classified as Hedging Instruments

The following table presents outstanding oil derivative contracts with respect to future production as of September 30, 2013:

					Contract Prices per Barrel of Oil		
		Type of	Pricing	Volume		Weighted Average Price	
Year	Months	Contract	Index	(Barrels per day)	Range	Floor	Ceiling
2013	Oct – Dec	Collar	NYMEX	54,000	$ 80.00 – 127.50	$80.00	$117.53
2014	Jan – Mar	Collar	NYMEX	58,000	$ 80.00 – 104.50	$80.00	$102.11
	Apr – June	Collar	NYMEX	58,000	80.00 – 104.50	80.00	102.11
	July – Sept	Collar	NYMEX	58,000	80.00 – 100.00	80.00	97.73
	Oct – Dec	Collar	NYMEX	58,000	80.00 – 100.00	80.00	97.73
2015	Jan – Mar	Collar	NYMEX	38,000	$ 80.00 – 100.90	$80.00	$96.96
	Jan – Mar	Collar	LLS	20,000	85.00 – 104.00	85.00	101.45
	Apr – June	Collar	NYMEX	38,000	80.00 – 95.25	80.00	94.62
	Apr – June	Collar	LLS	20,000	85.00 – 103.00	85.00	102.01
	July – Sept	Collar	NYMEX	30,000	80.00 – 95.25	80.00	95.06
	July – Sept	Collar	LLS	16,000	85.00 – 102.60	85.00	101.11

Additional Disclosures about Derivative Instruments

At September 30, 2013 and December 31, 2012, 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, 2013	December 31, 2012
		In thousands	
Derivative assets			
Crude oil contracts	Derivative assets – current	$167	$19,477
Crude oil contracts	Derivative assets – long-term	2,970	36
Derivative liabilities			
Crude oil contracts	Derivative liabilities – current	(40,261)	(2,659)
Deferred premiums	Derivative liabilities – current	—	(183)
Crude oil contracts	Derivative liabilities – long-term	(16,013)	(23,781)
Total derivatives not designated as hedging instruments		$(53,137)	$(7,110)

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, and all of our commodity derivative contracts are with parties that are lenders under our Bank

Credit Agreement. As of September 30, 2013, all of our outstanding derivative contracts were subject to enforceable master netting arrangements whereby payables on those contracts can be offset against receivables from separate derivative contracts with the same counterparty. It is our policy to classify derivative assets and liabilities on a gross basis on our balance sheets, even if the contracts are subject to enforceable master netting arrangements.

Note 6. Fair Value Measurements

The FASC Fair Value Measurements and Disclosures topic defines fair value as the price that would be received to sell an asset or would be 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. We currently have no Level 1 recurring measurements.

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil derivatives that are based on NYMEX pricing. Our 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. At September 30, 2013, instruments in this category include non-exchange-traded oil collars that are based on regional pricing other than NYMEX (i.e., Louisiana Light Sweet). Our costless collars are valued using the Black-Scholes model, which is described above. We obtain and ensure the appropriateness of the significant inputs to the calculation, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. Implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. A one percent increase or decrease in implied volatility would result in a change of approximately $0.1 million in the fair value of these instruments as of September 30, 2013.

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

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

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, 2013				
Assets:				
Oil derivative contracts	$—	$1,251	$1,886	$3,137
Liabilities:				
Oil derivative contracts	—	(54,534)	(1,740)	(56,274)
Total	$—	$(53,283)	$146	$(53,137)
December 31, 2012				
Assets:				
Oil derivative contracts	$—	$19,513	$—	$19,513
Liabilities:				
Oil derivative contracts	—	(26,440)	—	(26,440)
Total	$—	$(6,927)	$—	$(6,927)

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 our Unaudited Condensed Consolidated Statements of Operations.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

During the first quarter of 2012, we recorded a $15.1 million impairment charge for an investment in the preferred stock of Faustina Hydrogen Products LLC, which impairment was 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. We use a market approach to determine fair value of our fixed-rate debt using observable market data. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our total long-term debt as of September 30, 2013 and December 31, 2012, excluding pipeline financing and capital lease obligations, was $2.921 billion and $2.957 billion, respectively. 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.

Delhi Field Release

In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil, was discovered and reported within an area of the Denbury-operated Delhi Field located in northern Louisiana. Denbury immediately took remedial action to stop the release and contain and recover well fluids in the affected area. We have determined that the release originated from one or more wells in the affected area of the field that had been previously plugged and abandoned by a prior operator of the field. We currently expect that our ongoing remediation efforts will be completed during the fourth quarter of 2013; however we will continue to monitor the area for a period of time thereafter to ensure the remediation efforts were successful.

During the three and nine months ended September 30, 2013, we recorded $28.0 million and $98.0 million, respectively, of lease operating expenses related to this release in our Unaudited Condensed Consolidated Statement of Operations, and as of September 30, 2013 we had a corresponding $31.3 million liability classified as “Accounts payable and accrued liabilities” in our Unaudited Condensed Consolidated Balance Sheet. These expenses represent our current estimate of the costs to remediate this release based on actual costs incurred through October 31, 2013 of approximately $85 million, plus the Company's estimate of future costs related to the satisfaction of known claims and liabilities. Due to the possibility of new claims being asserted in the future in connection with the release, as well as variability in the costs of certain of our remediation-related activities which have been identified and/or begun but which have not been completed, we cannot reliably estimate at this time the full extent of the costs that may ultimately be incurred by the Company related to this release. Although the Company maintains insurance policies which we believe cover certain of the costs and damages related to the release, and we currently estimate that one-third to two-thirds of our current cost estimate may be recoverable under such insurance policies, we have not reached any agreement with our insurance carriers as to recoverable amounts, and accordingly have not recognized any such recoveries in our financial statements as of September 30, 2013. Insurance recoveries will be recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain.

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 Unaudited Condensed Consolidated Financial Statements and Notes thereto included herein and our Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2012 (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 section for information on the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

OVERVIEW

Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. We are the largest combined oil and natural gas producer in both Mississippi and Montana, and we own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River. 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 relating to tertiary recovery operations.

Operating Highlights. During the third quarter of 2013, we recognized net income of $102.1 million, or $0.28 per diluted common share, compared to net income of $85.4 million, or $0.22 per diluted common share, during the third quarter of 2012. The improved financial results between comparative third quarters of 2013 and 2012 were primarily driven by improved oil prices which helped to generate a $78.6 million increase in oil and natural gas revenues between the two periods, which was largely offset by (1) a $50.5 million increase in lease operating expense in the most recent quarter ($28.0 million of which constitutes remediation cost estimates for an area of Delhi Field) and (2) an increase of $18.8 million in derivatives expense (primarily due to an $11.9 million increase in the change in the noncash fair value of our commodity derivative contracts between the two periods). See Results of Operations – Operating Results Summary – Delhi Field Release below for more information. The 27% improvement in diluted EPS between the two periods is further impacted by a reduction in shares outstanding since September 30, 2012 due to the continued purchases under our share repurchase program (see Capital Resources and Liquidity – Share Repurchase Program below).

During the third quarter of 2013, our average oil and natural gas production, which was 95% oil, decreased 2%, from 72,776 BOE/d produced during the third quarter of 2012 to an average of 71,531 BOE/d produced during the third quarter of 2013. This decline in production was primarily due to declines in our non-tertiary producing assets and slightly lower production due to the sale and exchange of our Bakken area assets preceding our purchase of additional interests in the Cedar Creek Anticline ("CCA"), offset in part by increased tertiary production. Our tertiary oil production averaged 37,513 Bbls/d during the third quarter of 2013, an increase of 8% over the 34,786 Bbls/d produced during the third quarter of 2012, but decreased 3% from our average tertiary production of 38,752 Bbls/d in the second quarter of 2013 due primarily to our incident at Delhi Field (See Delhi Field Release below). See Results of Operations – Operating Results Summary – Production for more information.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, increased 14% to $105.91 per Bbl during the third quarter of 2013, compared to $93.09 per Bbl during the third quarter of 2012. Our realized oil price for the third quarter of 2013 was $0.03 per Bbl below NYMEX oil prices compared to $0.80 per Bbl above NYMEX oil prices in the prior-year period. Sequentially, our average realized oil price increased from the $98.92 per Bbl realized price in the second quarter of 2013; however, our average realized oil price differential was $4.78 per Bbl above NYMEX in the second quarter of 2013 compared to $0.03 per Bbl below NYMEX in the current quarter. Our oil and natural gas revenues during the third quarter of 2013 were a Company record high at $666.8 million. See Results of Operations – Operating Results Summary – Oil and Natural Gas Revenues below for more information on our oil prices received and differentials to NYMEX prices.

Cedar Creek Anticline Acquisition. On March 27, 2013, we closed our acquisition of producing assets in the CCA of Montana and North Dakota in a purchase from a wholly-owned subsidiary of ConocoPhillips Company ("ConocoPhillips") for $1.0 billion in cash, after final closing adjustments primarily for revenues and costs of the purchased properties from the January 1, 2013 effective date to the closing date. We funded the acquisition with a portion of the cash proceeds from the Bakken exchange transaction, $1.05 billion of which was placed in qualifying trust accounts in order to qualify the acquisition for like-kind-exchange treatment under federal income tax rules. The assets purchased include both additional interests in certain of our existing operated fields in CCA, as well as operating interests in other CCA fields. In conjunction with this acquisition, we added 42.2 MMBOE of estimated proved reserves.

Rocky Mountain Tertiary Operations Startup. In late 2012, we completed construction of the first section of the 20-inch Greencore Pipeline in Wyoming, our first CO_2 pipeline in the Rocky Mountain region, and received our first CO_2 deliveries from the Lost Cabin gas plant in central Wyoming during the first quarter of 2013. We started injections at our Bell Creek Field in Montana during the second quarter of 2013, with the first tertiary oil production from this field during the third quarter of 2013. In December 2012, we completed the required three-mile CO_2 pipeline to deliver CO_2 from our source at LaBarge Field to Grieve Field in Wyoming and began injecting CO_2 into Grieve Field during the first quarter of 2013. We currently expect tertiary production from Grieve Field to commence in 2015. We currently expect to complete the Riley Ridge gas processing facility during the first quarter of 2014.

Debt Refinancing. In February 2013, we issued $1.2 billion of 4 5/8% Senior Subordinated Notes due 2023 (the "2023 Notes"). The net proceeds of approximately $1.18 billion were used to repurchase or redeem our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes"), our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") and to pay down a portion of outstanding borrowings on our bank credit facility. During the nine months ended September 30, 2013, we recognized a loss associated with the debt repurchases of $44.7 million, which is included in our Unaudited Condensed Consolidated Statement of Operations under the caption "Loss on early extinguishment of debt". See Note 3, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements for additional details surrounding the repurchase and redemption of our 9½% Notes and 9¾% Notes.

Addition of Proved CO_2 Reserves. During the first nine months of 2013, we added approximately 350 Bcf of estimated proved CO_2 reserves as a result of successful drilling in the Jackson Dome area, our primary source of CO_2 for the Gulf Coast region.

Evaluation of Means of Distributing Future Free Cash Flow to Stockholders. The Company has substantially completed its internal analysis of options for distributing expected future free cash flow to stockholders. In general, this analysis includes evaluation of different organizational structures, and the timing of development of future capital projects. The Company will announce its decisions growing out of this analysis in connection with its November 11, 2013 analyst meeting.

Delhi Field Release. In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil, was discovered and reported within the Denbury-operated Delhi Field located in northern Louisiana. Denbury immediately took remedial action to stop the release and contain and recover well fluids in the affected area. We have determined that the release originated from one or more wells in the affected area of the field that had been previously plugged and abandoned by a prior operator of the field. We currently expect that our ongoing remediation efforts will be completed during the fourth quarter of 2013; however, we will continue to monitor the area for a period of time thereafter to ensure the remediation efforts were successful.

During the three and nine months ended September 30, 2013, we recorded $28.0 million and $98.0 million, respectively, of lease operating expenses related to this release in our Unaudited Condensed Consolidated Statement of Operations, which year-to-date amount represents our current estimate of the costs to remediate this release based on actual costs incurred through October 31, 2013 of approximately $85.0 million, plus the Company’s estimate of future costs related to the satisfaction of known claims and liabilities. Due to the possibility of new claims being asserted in the future in connection with the release, as well as variability in the costs of certain of our remediation-related activities which have been identified and/or begun but which have not been completed, we cannot reliably estimate at this time the full extent of the costs that may ultimately be incurred by the Company related to this release. Although the Company maintains insurance policies which we believe cover certain of the costs and damages related to the release, and we currently estimate that one-third to two-thirds of our current cost estimate may be recoverable under such insurance policies, we have not reached any agreement with our insurance carriers as to recoverable amounts, and accordingly have not recognized any such recoveries in our financial statements as of September 30, 2013. Insurance recoveries will be recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain. See Note 7, Commitments and Contingencies to the Unaudited Condensed Consolidated Financial Statements for further discussion.

CAPITAL RESOURCES AND LIQUIDITY

2013 Capital Spending. We anticipate that our full-year 2013 capital budget, excluding acquisitions, will be $1.06 billion, plus approximately $160 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods. This combined 2013 capital expenditure amount of $1.22 billion, excluding acquisitions, is comprised of the following:

- $580 million allocated for tertiary oil field expenditures;
- $110 million for pipeline construction;
- $200 million to be spent on CO_2 sources;
- $170 million to be spent in all other areas; and
- $160 million for other capital items such as capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.

During the nine months ended September 30, 2013, we incurred capital expenditures of approximately $843.2 million, exclusive of property acquisitions. See additional detail on our expenditures in the Capital Expenditure Summary below.

Based on oil and natural gas commodity futures prices in early November 2013 and our current production forecast, we expect our 2013 cash flow from operations to be more than adequate to cover our 2013 capital budget. If prices were to decrease or changes in operating results were to cause us to have a significant reduction in anticipated 2013 cash flows, we have ample availability on our bank credit facility to cover any potential shortfall, and we also have the ability to reduce our capital expenditures if desired. In addition, we have oil derivative contracts in place with an $80 NYMEX floor price for a significant portion of our anticipated oil production through September 2015 to provide an economic hedge of our exposure to commodity prices. See Note 5, Derivative Instruments to the Unaudited Condensed Consolidated Financial Statements for details of our oil commodity contracts.

We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital spending up or down depending on cash flows; however, any such reduction in capital spending could reduce our anticipated production levels in future years. For 2013 and some 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 of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations in the Form 10-K).

Bank Credit Facility. Our primary source of capital is our cash flow from operations. We use our bank credit facility as needed for acquisitions and to bridge the relatively minor timing differences between our cash flow generated from operations and our capital expenditure program. As part of our semiannual bank review, the borrowing base for our bank credit facility was reaffirmed at $1.6 billion in late October 2013. Our next borrowing base redetermination is scheduled on or around May 1, 2014. We currently do not anticipate any reduction in our borrowing base as part of that redetermination, and we believe, based on current commodity prices and our proved asset base, that we could obtain lender approval to significantly increase the borrowing base under our bank credit facility above the current $1.6 billion level if we desired to do so. As of September 30, 2013, we had $1.3 billion of unused availability under our bank credit facility and cash of $26.5 million, leaving us significant liquidity to fund any cash shortfall for capital expenditures.

Share Repurchase Program. Since its commencement in October 2011, our Board of Directors has authorized a common share repurchase program for up to $771.2 million of our common shares, under which we have repurchased 11.7 million shares of Denbury common stock for $200.0 million during the nine months ended September 30, 2013, which was funded with a combination of cash flow from operations and incremental borrowings. We have purchased a total of 42.8 million shares of Denbury common stock for $661.9 million, or an average of $15.48 per share, between commencement of the share repurchase program in October 2011 and September 30, 2013. As of September 30, 2013, we have $109.3 million remaining under our authorized share repurchase program. See Note 4, Share Repurchase Program to the Unaudited Condensed Consolidated Financial Statements for further discussion. Our share repurchases will be determined based on various parameters; therefore, our share repurchases may be less than the remaining approved balance under the program and there is no set expiration date for our program. We anticipate that additional repurchases during 2013 will be primarily funded with excess cash flow from operations or with borrowings under our bank credit facility.

Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30,	
In thousands	2013	2012
Capital expenditures by project:		
Tertiary oil fields	$449,130	$340,698
CO_2 pipelines	39,363	114,738
CO_2 sources [1]	114,240	186,836
Other areas	175,687	452,720
Capitalized interest	64,752	57,357
Capital expenditures before acquisitions	843,172	1,152,349
Less: recoveries from sale/leaseback transactions	—	(35,102)
Net capital expenditures excluding acquisitions	843,172	1,117,247
Property acquisitions [2]	1,062,607	369,580
Capital expenditures, net of sale/leaseback transactions	$1,905,779	$1,486,827

(1) Includes capital expenditures related to the Riley Ridge gas plant.

(2) Property acquisitions during the nine months ended September 30, 2013 include capital expenditures of approximately $1.1 billion related to acquisitions during the period 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.

For the first nine months of 2013, our capital expenditures other than those for property acquisitions were funded with cash flow from operations, and those for property acquisitions were funded with proceeds from the Bakken exchange transaction (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 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.

Off-Balance Sheet Arrangements. Our off-balance sheet arrangements include operating leases for office space and various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports.

Our commitments and obligations consist of those detailed as of December 31, 2012 in our Form 10-K under Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and

Liquidity – Commitments and Obligations, plus estimated obligations related to the Delhi Field release (some of which have not been completed or are contingent and/or cannot yet be quantified). See Note 7, Commitments and Contingencies, to the Unaudited Condensed Consolidated Financial Statements for further discussion.

RESULTS OF OPERATIONS

Our tertiary operations represent a significant portion of our overall operations and are our primary strategic focus. The economics of a tertiary field and the related impact on our financial statements differ from a conventional oil and gas play, and we have outlined certain of these differences in our Form 10-K and other public disclosures. Our focus on these types of operations impacts certain trends in both current and long-term operating results. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Financial Overview of Tertiary Operations in our Form 10-K for further information regarding these matters.

Table of Contents
Denbury Resources Inc.
Management's Discussion and Analysis of Financial Condition and Results of Operations

Operating Results Summary

Certain of our operating results and statistics for the comparative third quarters and first nine months of 2013 and 2012 are included in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share and unit data	2013	2012	2013	2012
Operating results				
Net income	$102,054	$85,367	$319,605	$410,699
Net income per common share – basic	0.28	0.22	0.87	1.06
Net income per common share – diluted	0.28	0.22	0.86	1.05
Net cash provided by operating activities	305,465	293,506	1,012,209	1,026,126
Average daily production volumes				
Bbls/d	67,705	67,655	65,755	67,331
Mcf/d	22,957	30,724	24,451	29,318
BOE/d (1)	71,531	72,776	69,830	72,217
Operating revenues				
Oil sales	$659,674	$579,429	$1,855,006	$1,790,326
Natural gas sales	7,129	8,727	23,638	23,472
Total oil and natural gas sales	$666,803	$588,156	$1,878,644	$1,813,798
Commodity derivative contracts (2)				
Cash receipt (payment) on settlements of derivative contracts	$(662)	$6,269	$(662)	$12,361
Noncash fair value adjustments to derivative contracts – income (expense)	(79,784)	(67,900)	(46,212)	19,842
Total income (expense) from commodity derivative contracts	$(80,446)	$(61,631)	$(46,874)	$32,203
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$105.91	$93.09	$103.34	$97.04
Natural gas price per Mcf	3.38	3.09	3.54	2.92
Unit prices – including impact of derivative settlements (2)				
Oil price per Bbl	$105.80	$92.99	$103.30	$96.52
Natural gas price per Mcf	3.38	5.53	3.54	5.65
Oil and natural gas operating expenses				
Lease operating expenses (3)	$180,967	$130,485	$542,067	$392,960
Marketing expenses	13,131	14,728	36,259	37,776
Production and ad valorem taxes	46,073	37,412	122,542	114,699
Oil and natural gas operating revenues and expenses per BOE (1)				
Oil and natural gas revenues	$101.32	$87.84	$98.55	$91.66
Lease operating expenses (3)	27.50	19.49	28.43	19.86
Marketing expenses, net of third-party purchases	1.39	1.52	1.45	1.48
Production and ad valorem taxes	7.00	5.59	6.43	5.80
CO_2 revenues and expenses				
CO_2 sales and transportation fees	$6,739	$7,160	$19,859	$19,256

CO_2 discovery and operating expenses [4]	(4,120)	(1,176)	(11,261)	(8,443)
CO_2 revenue and expenses, net	$2,619	$5,984	$8,598	$10,813

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

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

(3) Excluding estimated lease operating expense recorded during the three and nine months ended September 30, 2013 to remediate an area of Delhi Field (see Overview – Delhi Field Release above), lease operating expenses totaled $153.0 million and $444.1 million for the three and nine months ended September 30, 2013, respectively and lease operating expense per BOE averaged $23.24 and $23.29 for the three and nine months ended September 30, 2013, respectively.

(4) Includes $0.3 million and $0.8 million of exploratory costs during the three and nine months ended September 30, 2013 and $4.8 million during the nine months ended September 30, 2012. We incurred no exploratory costs during the three months ended September 30, 2012.

Production

Average daily production by area for each of the four quarters of 2012 and for the first, second, and third quarters of 2013 is shown below:

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2012	Second Quarter 2012	Third Quarter 2012	Fourth Quarter 2012	First Quarter 2013	Second Quarter 2013	Third Quarter 2013
Tertiary oil production							
Gulf Coast region							
Mature properties:							
Brookhaven	3,014	2,779	2,460	2,520	2,305	2,339	2,224
Eucutta	3,090	2,870	2,782	2,730	2,636	2,642	2,504
Mallalieu	2,585	2,461	2,181	2,127	2,116	2,157	2,042
Other mature properties (1)	8,012	7,867	7,347	7,605	7,800	7,233	6,761
Delhi	4,181	4,023	3,813	5,237	5,827	5,479	4,517
Hastings	618	1,913	2,794	3,409	3,956	4,010	3,699
Heidelberg	3,583	3,823	3,716	3,930	3,943	4,149	4,553
Oyster Bayou	877	1,304	1,540	1,826	2,252	2,518	3,213
Tinsley	7,297	8,168	8,153	8,166	8,222	8,225	7,951
Total Gulf Coast region	33,257	35,208	34,786	37,550	39,057	38,752	37,464
Rocky Mountain region							
Bell Creek	—	—	—	—	—	—	49
Total Rocky Mountain region	—	—	—	—	—	—	49
Total tertiary oil production	33,257	35,208	34,786	37,550	39,057	38,752	37,513
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	4,573	4,095	3,401	3,663	3,013	2,367	2,692
Texas	3,674	4,573	5,173	5,513	6,692	6,932	6,548
Other	1,281	1,306	1,137	1,217	1,153	1,108	1,087
Total Gulf Coast region	9,528	9,974	9,711	10,393	10,858	10,407	10,327
Rocky Mountain region							
Cedar Creek Anticline (2)	8,496	8,535	8,490	8,493	8,745	19,935	18,872
Other	3,204	3,060	3,037	3,616	5,163	4,958	4,819
Total Rocky Mountain region	11,700	11,595	11,527	12,109	13,908	24,893	23,691
Total non-tertiary production	21,228	21,569	21,238	22,502	24,766	35,300	34,018
Total continuing production	54,485	56,777	56,024	60,052	63,823	74,052	71,531
Properties disposed:							
Bakken area assets (3)	15,285	15,503	16,752	10,064	—	—	—
2012 Non-core asset divestitures (4)	1,762	57	—	—	—	—	—
Total production	71,532	72,337	72,776	70,116	63,823	74,052	71,531

(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.
(2) Beginning March 27, 2013, amounts include production from our purchase of additional interests in the CCA.

(3) Includes production from certain Bakken area assets sold in the fourth quarter of 2012.

(4) Includes production from certain non-core Gulf Coast assets sold in late February 2012 and certain non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012.

Total Production

Total production decreased 1,245 BOE/d (2%) between the third quarters of 2012 and 2013, with the most recent quarter including production from CCA assets acquired in late March 2013, and other assets acquired in the Bakken exchange transaction (see Note 2, Acquisitions and Divestitures, to the Unaudited Condensed Consolidated Financial Statements), while the 2012 quarter included production from our Bakken area assets sold in December 2012. On a year-to-date basis, total production decreased 2,387 BOE/d (3%) between the first nine months of 2012 and 2013, due primarily to the timing of the acquisition of CCA and the divestiture of Bakken area assets noted above. Our production during the three and nine months ended September 30, 2013 was 95% and 94% oil, respectively, slightly higher than oil production of 93% during the three and nine months ended September 30, 2012.

Tertiary Production

Oil production from our tertiary operations increased 8% when comparing the third quarters of 2013 and 2012, to 37,513 Bbls/d during the third quarter of 2013. This year-over-year increase was primarily due to production growth in response to continued field development and expansion of facilities in the tertiary floods in Delhi, Hastings, Heidelberg and Oyster Bayou fields, partially offset by normal declines in our mature tertiary fields.

On a sequential-quarter basis, tertiary oil production during the third quarter of 2013 decreased 1,239 Bbls/d (3%) compared to production levels in the second quarter of 2013 primarily due to decreased production at Delhi Field discussed below, as well as production declines at Hastings Field due to facility downtime resulting from a compressor failure and planned maintenance activities, and at our mature fields due to anticipated production declines. Production at Delhi Field declined in the third quarter of 2013 as the Company ceased CO_2 injections into a portion of this field late in the second quarter of 2013 (see Overview – Delhi Field Release above). Late in the third quarter of 2013, the Company resumed CO_2 injections into areas surrounding the impacted area of the field and as a result, Delhi Field production was approximately 4,600 Bbls/d in October 2013 and is expected to gradually increase during the fourth quarter of 2013. Costs incurred as a result of the release, together with lower production levels, are currently expected to delay the effective date of a third party's approximate 25% reversionary interest in the Delhi Field until sometime during 2014, the timing of which is largely dependent upon the amount and timing of any potential insurance proceeds and their application to the payout calculation, as well as oil prices, production, and production costs. We currently estimate that the payout date could range from late 2014 to early 2014 depending primarily upon the amount, timing and application of insurance proceeds to the payout calculation. We previously estimated the reversionary interest would decrease our share of production in Delhi Field during the latter half of 2013.

We realized our first tertiary oil production in the Rocky Mountain region in the third quarter of 2013 at Bell Creek Field. We anticipate production growth at this field in the remainder of 2013 as we continue to develop the field.

Non-Tertiary Production

Continuing production from our non-tertiary operations increased to 34,018 BOE/d during the third quarter of 2013, an increase of 12,780 BOE/d compared to third quarter 2012 levels. The non-tertiary continuing production increases were primarily due to production from newly acquired fields, specifically CCA acquired in March 2013 and Webster and Hartzog Draw fields acquired in the Bakken exchange transaction in late 2012. Sequentially, continuing production from our non-tertiary operations decreased 1,282 BOE/d (4%) compared to second quarter 2013 levels, due primarily to lower production at CCA. CCA production was lower sequentially due to downtime in several CCA fields during the third quarter for repairs and maintenance, shut-ins due to severe weather, and a higher net profits interest of a third party. Higher oil prices result in a higher net profits interest, which lowers our production quantities. With the exception of the impact of production added from fields acquired during 2012 and 2013, production from our other non-tertiary properties is generally on decline, and in some instances the decline may appear larger than normal due to the expansion of our tertiary floods in certain fields which causes non-tertiary production generally to be shut in for a period while the field is being pressured up.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and nine months ended September 30, 2013 increased 13% and 4%, respectively, compared to these revenues for the same periods in 2012. The increase in both periods is primarily related to increases in commodity prices, partially offset by decreases in production. The change in oil and natural gas revenues due to these factors, excluding any impact of our derivative contracts, is reflected in the following table:

	Three Months Ended September 30, 2013 vs. 2012		Nine Months Ended September 30, 2013 vs. 2012	
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:				
Decrease in production	$(10,061)	(2)%	$(66,343)	(3)%
Increase in commodity prices	88,708	15%	131,189	7%
Total increase in oil and natural gas revenues	$78,647	13%	$64,846	4%

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, 2013 and 2012:

	Three Months Ended March 31,		Three Months Ended June 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
Net realized prices:								
Oil price per Bbl	$105.59	$102.52	$98.92	$95.63	$105.91	$93.09	$103.34	$97.04
Natural gas price per Mcf	3.28	3.84	3.96	1.87	3.38	3.09	3.54	2.92
Price per BOE	99.87	97.32	94.70	89.96	101.32	87.84	98.55	91.66
NYMEX differentials:								
Oil per Bbl	$11.17	$(0.37)	$4.78	$2.14	$(0.03)	$0.80	$5.13	$0.84
Natural gas per Mcf	(0.21)	1.32	(0.05)	(0.49)	(0.18)	0.20	(0.15)	0.33

As reflected in the table above, our average net realized oil price increased 14% during the third quarter of 2013, compared to the average price received during the third quarter of 2012. Company-wide oil price differentials in the third quarter of 2013 were $0.03 per Bbl below NYMEX, compared to an average differential of $0.80 per Bbl above NYMEX in the third quarter of 2012. During the third quarter of 2013, we sold approximately 44% of our 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. The net differential we received was 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.

We received favorable NYMEX oil differentials in the Gulf Coast region during the three and nine months ended September 30, 2013 and 2012, primarily due to the favorable differential for crude oil sold under Light Louisiana Sweet ("LLS") index prices. This LLS-to-NYMEX differential declined during the third quarter of 2013 from a positive $15.05 per Bbl average differential on a trade-month basis in the third quarter of 2012 and a positive $15.07 per Bbl in the second quarter of 2013 to a positive $6.59 per Bbl in the third quarter of 2013.

NYMEX oil differentials in the Rocky Mountain region during the third quarter of 2013 were $7.04 per Bbl below NYMEX, compared to an average differential of $13.82 per Bbl below NYMEX in the third quarter of 2012 and $6.77 per Bbl below NYMEX in the second quarter of 2013. The change in the differential between 2012 and 2013 was largely impacted by the sale of our Bakken area assets in December 2012, as oil from the disposed properties sold at a significant discount to NYMEX during 2012, all due to increased production in the area coupled with limited transportation infrastructure.

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. Accordingly, early in the fourth quarter of 2013, we observed a decline in the favorable LLS-to-NYMEX differential to an average of approximately $2 positive to NYMEX and a widening of the Rocky Mountain differential such that it is trading lower in relation to NYMEX than third quarter of 2013 levels. If these trends continue, we would expect our Company-wide differential to be negative to NYMEX during the fourth quarter of 2013.

Oil and Natural Gas Derivative Contracts

The following tables summarize the impact our oil and natural gas derivative contracts had on our operating results for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,					
	2013	2012	2013	2012	2013	2012
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Cash settlement receipts (payments)	$(662)	$(641)	$—	$6,910	$(662)	$6,269
Noncash fair value loss	(79,784)	(60,726)	—	(7,174)	(79,784)	(67,900)
Total	$(80,446)	$(61,367)	$—	$(264)	$(80,446)	$(61,631)

	Nine Months Ended September 30,					
	2013	2012	2013	2012	2013	2012
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Cash settlement receipts (payments)	$(662)	$(9,580)	$—	$21,941	$(662)	$12,361
Noncash fair value loss	(46,212)	37,752	—	(17,910)	(46,212)	19,842
Total	$(46,874)	$28,172	$—	$4,031	$(46,874)	$32,203

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period change in the fair value of these contracts, as outlined above, is recognized in our statements of operations. Our derivative contracts for 2013 and beyond are currently all NYMEX and LLS oil contracts given that our current and forecasted production is primarily oil (95% of volumes on a BOE-basis in the third quarter of 2013), leading us to focus at the current time solely on oil derivative contracts in our commodity market risk management program. We may enter into natural gas derivative contracts in the future as the natural gas market improves and as we anticipate our natural gas production will increase with the expected completion of the Riley Ridge gas processing facility in the first quarter of 2014. See Notes 5 and 6 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

Production Expenses

Lease operating expense

In thousands, except per-BOE data	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Lease operating expense				
Tertiary – excluding Delhi Field remediation	$86,534	$75,202	$256,283	$229,660
Tertiary – Delhi Field remediation	28,000	—	98,000	—
Non-tertiary	66,433	55,283	187,784	163,300
Total lease operating expense	$180,967	$130,485	$542,067	$392,960
Lease operating expense per BOE				
Tertiary – excluding Delhi Field remediation	$25.08	$23.50	$24.42	$24.35
Tertiary – Delhi Field remediation	8.11	—	9.34	—
Non-tertiary	21.23	15.82	21.91	15.77
Total lease operating expense per BOE [1]	27.50	19.49	28.43	19.86

(1) Excluding estimated lease operating expense recorded during the three and nine months ended September 30, 2013 to remediate an area of Delhi Field (see Overview – Delhi Field Release above), total lease operating expense per BOE averaged $23.24 and $23.29 for the three and nine months ended September 30, 2013, respectively.

Total lease operating expense during the three and nine months ended September 30, 2013 increased from the comparable 2012 periods on an absolute-dollar and per-BOE basis primarily due to $28.0 million and $98.0 million in estimated lease operating expenses recorded during the three and nine months ended September 30, 2013, respectively, which represents our current estimate of the costs to remediate an area of Delhi Field impacted by a release of well fluids discovered in mid-June (see Overview – Delhi Field Release above). Excluding these estimated remediation expenses, lease operating expense increased $22.5 million and $51.1 million, respectively, during the three and nine months ended September 30, 2013 compared to the same periods in 2012 due primarily to increased expenses resulting from our acquisition of additional interests in CCA late in the first quarter of 2013, expansion of our CO_2 floods, and increases in the cost of CO_2 between the comparative periods. Excluding the estimated Delhi Field remediation costs recorded during the second and third quarters of 2013, lease operating expense increased $3.75 and $3.43 per BOE for the three and nine months ended September 30, 2013, respectively, compared to the prior year periods. The increase in each period is primarily due to the sale of the Bakken area assets in late 2012, which had a low operating cost per BOE, the addition of Hartzog Draw and Webster fields, and additional interests in the CCA, which have a higher operating cost per BOE than the Bakken area assets.

Excluding the estimated Delhi Field remediation expense, tertiary lease operating expense increased $11.3 million and $26.6 million, respectively, during the three and nine months ended September 30, 2013 compared to the same periods in 2012. These increases were primarily a result of the expansion of our CO_2 floods and increased CO_2 expenses due to increases in the cost of CO_2 between both comparative periods and an increase in CO_2 volumes injected into producing CO_2 fields between the three- and nine-month comparative periods. See Overview – Delhi Field Release above for a discussion of the estimated costs we expect to incur to remediate Delhi Field.

Currently, our CO_2 expense comprises approximately one-fourth of our typical Gulf Coast tertiary operating expenses, and for the CO_2 reserves we already own, consists of our CO_2 production expenses, and for the CO_2 reserves we do not own, consists of our purchase of CO_2 from royalty and working interest owners and anthropogenic (man-made) sources. During the third quarter of 2013, approximately 70% of the CO_2 utilized in our Gulf Coast region CO_2 floods consisted of CO_2 owned and produced by us and the remaining portion we purchased from third-party owners (primarily royalty owners). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties for CO_2, our average cost of CO_2 for the Gulf Coast region during the third quarter of 2013 was approximately $0.33 per Mcf, including taxes paid on CO_2 production but excluding depreciation and amortization of capital expended at our Jackson Dome source and CO_2 pipelines. This rate during the third quarter of 2013 was higher than the $0.25 per Mcf spent during the third quarter of 2012 primarily due to higher oil prices (to which the cost of CO_2 is partially tied) and increased volumes purchased from anthropogenic sources during 2013, which volumes have a higher purchase price but require a smaller capital outlay than CO_2 we obtain from the Jackson Dome area. Including the cost of depreciation and amortization expense related to the Jackson Dome CO_2 production but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was $0.42 per Mcf and $0.32 per Mcf during the third quarter of 2013 and 2012, respectively.

Excluding the estimated Delhi remediation expense, tertiary operating expense averaged $25.08 and $24.42 per Bbl during the three and nine months ended September 30, 2013, respectively, representing a 7% increase per Bbl compared to the three-month period in 2012, primarily due to the higher CO_2 costs discussed above, and consistent with the nine-month period. See Overview – Delhi Field Release above for a discussion of the estimated costs we expect to incur to remediate Delhi Field.

Non-tertiary lease operating expense increased 20% and 15% on an absolute-dollar basis during the three and nine months ended September 30, 2013, respectively, compared to the same prior-year periods, as declines resulting from the sale of our Bakken area assets were more than offset by increases in newly acquired fields, including Thompson field acquired in June 2012, Webster and Hartzog Draw fields acquired in the Bakken exchange transaction in late 2012, and additional interests in CCA acquired in March 2013. On a per-BOE basis, non-tertiary lease operating expense during the three and nine months ended September 30, 2013 increased 34% and 39%, respectively, compared to the same prior-year periods due to increases in newly acquired fields, which have a higher per-BOE operating cost than the properties disposed in the Bakken exchange transaction.

Taxes other than income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income increased $9.3 million and $9.7 million during the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. The change in each period is generally aligned with fluctuations in oil and natural gas revenues. The increase during both comparative periods is further impacted by the change in the mix of properties subject to production and ad valorem taxes as a result of the Bakken exchange transaction and CCA acquisition.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and employees	2013	2012	2013	2012
Gross cash compensation and administrative costs	$82,653	$76,192	$247,171	$221,991
Gross stock-based compensation	10,032	9,247	30,791	29,205
Operator labor and overhead recovery charges	(43,272)	(34,659)	(125,064)	(104,665)
Capitalized exploration and development costs	(13,444)	(12,582)	(41,658)	(36,900)
Net G&A expense	$35,969	$38,198	$111,240	$109,631
G&A per BOE:				
Net administrative costs	$4.32	$4.70	$4.69	$4.50
Net stock-based compensation	1.15	1.01	1.15	1.04

Net G&A expense	$5.47	$5.71	$5.84	$5.54
Employees as of September 30	1,494	1,423		

Net G&A expense decreased 6% on an absolute-dollar basis and 4% on a per-BOE basis between the three months ended September 30, 2012 and September 30, 2013, and increased 1% on an absolute-dollar basis and 5% on a per-BOE basis between the nine months ended September 30, 2012 and September 30, 2013.

Gross administrative costs increased $6.5 million (8%) and $25.2 million (11%) during the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. The increase between the comparative three- and nine-month periods was primarily due to higher compensation-related costs driven primarily from an increase in employee headcount (5%) and annual merit increases.

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. In addition, salaries associated with field personnel are initially recorded as gross cash compensation and administrative costs and subsequently reclassified to lease operating expenses or capitalized to field development costs to the extent those individuals are dedicated to oil and gas production, exploration, and development activities. As a result of additional operated wells, increased compensation expense and an increase in the COPAS overhead rate, the amount we recovered as operator labor and overhead charges increased by 25% and 19% during the three and nine months ended September 30, 2013, respectively, compared to the amounts recovered in the same periods in 2012. Capitalized exploration and development costs 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	2013	2012	2013	2012
Cash interest expense	$50,828	$53,569	$155,308	$161,978
Noncash interest expense	3,441	3,695	10,581	11,124
Less: Capitalized interest	(19,768)	(19,437)	(64,752)	(57,357)
Interest expense, net	$34,501	$37,827	$101,137	$115,745
Interest expense, net per BOE	$5.24	$5.65	$5.31	$5.85
Average debt outstanding	$3,278,972	$3,073,450	$3,260,030	$2,874,146
Average interest rate [1]	6.2%	7.0%	6.4%	7.5%

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

Interest expense, net decreased 9% and 13% between the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. The decrease in interest expense is due to higher capitalized interest and a lower average interest rate, partially offset by higher average debt outstanding. The decrease in the average interest rate is a result of refinancing our 9½% Notes and 9¾% Notes with our 2023 Notes, which carry a rate of 4 5/8% (see Overview – Debt Refinancing above). The increase in capitalized interest between the three and nine months ended September 30, 2012 and 2013 relates primarily to incremental capitalized interest on construction projects, as well as capitalized interest on enhanced oil recovery development projects.

Table of Contents
Denbury Resources Inc.
Management’s Discussion and Analysis of Financial Condition and Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data	2013	2012	2013	2012
Depletion and depreciation of oil and natural gas properties	$98,473	$112,617	$283,579	$328,952
Depletion and depreciation of CO_2 properties	6,603	5,829	20,872	16,365
Asset retirement obligations	2,117	1,992	6,337	5,516
Depreciation of other fixed assets	18,402	16,497	54,612	39,286
Total DD&A	$125,595	$136,935	$365,400	$390,119
DD&A per BOE:				
Oil and natural gas properties	$15.28	$17.12	$15.21	$16.90
CO_2 and other fixed assets	3.80	3.33	3.96	2.82
Total DD&A cost per BOE	$19.08	$20.45	$19.17	$19.72

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. In addition, under full cost accounting rules, the divestiture of oil and gas properties generally does not result in gain or loss recognition; instead, the proceeds of the disposition reduce the full cost pool. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. Depletion and depreciation of oil and natural gas properties decreased 13% and 14% on an absolute-dollar basis for the three and nine months ended September 30, 2013, respectively, and decreased 11% and 10% on a per-BOE basis for the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. These decreases were primarily due to the sale and exchange of our Bakken area assets for other property interests in late 2012, partially offset by the impact of the CCA acquisition in March 2013. As a result of this exchange, there was a net decrease in costs subject to depletion, partially offset by a reduction in total proved reserves.

Depletion and depreciation of our CO_2 properties and other fixed assets increased on an absolute-dollar and per-BOE basis during the three and nine months ended September 30, 2013 compared to the same periods in 2012 primarily due to an increase in CO_2 properties, pipelines and plants subject to depreciation as a result of continued development. The increase during the nine months ended September 30, 2013 was further impacted by a change in classification of our equipment leases from operating to capital during the second quarter of 2012, and the amount on a per-BOE basis was also impacted by lower oil and natural gas production during the first quarter of 2013. See Note 5, Long-term Debt, of our 2012 Consolidated Financial Statements in the Form 10-K for further discussion of the change in classification of our equipment leases.

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, 2013; however, if oil or 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 could offtake CO_2, as a result of the project not moving forward. 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	2013	2012	2013	2012
Current income tax expense	$16,019	$4,342	$23,367	$33,834
Deferred income tax expense	41,292	49,670	169,634	216,959
Total income tax expense	$57,311	$54,012	$193,001	$250,793
Average income tax expense per BOE	$8.71	$8.07	$10.12	$12.67
Effective tax rate	36.0 %	38.8 %	37.7 %	37.9 %

Our income taxes are based on estimated statutory rates of approximately 38.5% and 38% in 2013 and 2012, respectively. For the three and nine months ended September 30, 2013, our effective tax rate was below our estimated statutory rate primarily due to a change in the expected completion date of the Riley Ridge gas processing facility, from the fourth quarter of 2013 to the first quarter of 2014 as well as the change in treatment of certain items between our 2012 tax provision and our 2012 filed tax returns. The higher level of current taxes in the third quarter of 2013 was primarily due to the new expected completion date of the Riley Ridge gas processing facility, which reduced the Company's estimate of tax deductions expected to be realized in 2013.

As of September 30, 2013, after finalization of our 2012 tax return, we had an estimated $15.0 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2013 or future years, but cannot be used to offset alternative minimum tax. The enhanced oil recovery credits do not begin to expire until 2025. 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.

Table of Contents
Denbury Resources Inc.
Management's Discussion and Analysis of Financial Condition and Results of Operations

Per-BOE Data

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Per-BOE data	2013	2012	2013	2012
Oil and natural gas revenues	$101.32	$87.84	$98.55	$91.66
Gain (loss) on settlements of derivative contracts	(0.10)	0.93	(0.03)	0.63
Lease operating expenses – excluding Delhi Field remediation	(23.24)	(19.49)	(23.29)	(19.86)
Lease operating expenses – Delhi Field remediation	(4.26)	—	(5.14)	—
Production and ad valorem taxes	(7.00)	(5.59)	(6.43)	(5.80)
Marketing expenses, net of third party purchases	(1.39)	(1.52)	(1.45)	(1.48)
Production netback	65.33	62.17	62.21	65.15
CO_2 sales, net of operating and exploration expenses	0.39	0.89	0.45	0.54
General and administrative expenses	(5.47)	(5.71)	(5.84)	(5.54)
Interest expense, net	(5.24)	(5.65)	(5.31)	(5.85)
Other	(1.57)	0.61	(0.29)	(0.51)
Changes in assets and liabilities relating to operations	(7.02)	(8.47)	1.88	(1.93)
Cash flow from operations	46.42	43.84	53.10	51.86
DD&A	(19.08)	(20.45)	(19.17)	(19.72)
Deferred income taxes	(6.28)	(7.42)	(8.89)	(10.96)
Loss on early extinguishment of debt	—	—	(2.34)	—
Noncash commodity derivative adjustments	(12.12)	(10.13)	(2.42)	1.00
Impairment of assets	—	—	—	(0.89)
Other noncash items	6.57	6.91	(3.51)	(0.53)
Net income	$15.51	$12.75	$16.77	$20.76

CRITICAL ACCOUNTING POLICIES

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Actual costs can vary from such estimates for a variety of reasons. The costs of environmental remediation or litigation can vary from estimates due to new developments regarding the facts and circumstances of each event, including in the case of environmental remediation, the timing of remediation, our understanding of the environmental impact, remediation methods available, and regulatory requirements, and in the case of litigation, differing interpretations of laws and facts and assessments of damages asserted and/or incurred.

Other Critical Accounting Policies

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

Table of Contents
Denbury Resources Inc.
Management’s Discussion and Analysis of Financial Condition and Results of Operations

FORWARD-LOOKING INFORMATION

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in 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 Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted production, cash flows and capital expenditures, drilling activity or methods including the timing and location thereof, pending or planned acquisitions or dispositions, development activities, estimated timing of completion of pipeline construction and the cost thereof, 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, estimates of the range of potential insurance recoveries, estimates of costs of remedial activities, 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,” “to our knowledge,” “anticipate,” “project “preliminary,” “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 and remediation costs; disruption of operations and damages from well incidents, 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 Company's most recent Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Long-term Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in the event of significant downgrades of our corporate credit rating by the rating agencies, certain credit enhancements can be required from us, and possibly other remedies made available under the lease. As of September 30, 2013, our borrowings on our bank credit facility were $310.0 million, with a weighted average interest rate of 1.7%. 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, 2013:

In thousands	2014	2015	2016	2017	2020	2021	2023	Total
Variable rate debt:								
Bank Credit Facility (weighted average interest rate of 1.7% at September 30, 2013)	$—	$—	$310,000	$—	$—	$—	$—	$310,000
Fixed rate debt:								
8¼% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—	—	996,273
6 3/8% Senior Subordinated Notes due 2021	—	—	—	—	—	400,000	—	400,000
4 5/8% Senior Subordinated Notes due 2023							1,200,000	1,200,000
Other Subordinated Notes	1,072	485	—	2,250	—	—	—	3,807

Oil and Natural Gas Derivative Contracts

We regularly 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. These contracts have consisted of price floors, costless collars and fixed price swaps. We do not hold or issue derivative financial instruments for trading purposes. The production that we hedge has varied from year to year, depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production for approximately two years in the future from the current quarter, as we believe it is important to protect our future cash flow for a period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our planned expenditures have long lead times. Because our current and forecasted production is primarily oil (95% of volumes on a BOE-basis during the third quarter of 2013), we currently hold only oil derivative contracts in our commodity market risk management program. We may enter into natural gas derivative contracts in the future as the natural gas market improves and as we anticipate our natural gas production to increase with the expected completion of the Riley Ridge gas processing facility in the first quarter of 2014. 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. All of our commodity derivative contracts are with parties that are lenders under our bank credit facility. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

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

At September 30, 2013, our derivative contracts were recorded at their fair value, which was a net liability of approximately $53.1 million, a $46.2 million increase from the $6.9 million net liability recorded at December 31, 2012. This change is primarily related to the expiration of oil derivative contracts during 2013 and changes in oil futures prices between December 31, 2012 and September 30, 2013.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of September 30, 2013, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil derivative contracts as shown in the following table:

In thousands	Receipt/ (Payment)
Based on:	
Futures prices as of September 30, 2013	$(1,287)
10% increase in prices	(159,057)
10% decrease in prices	6,595

Table of Contents

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company's management, including 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, 2013, 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 our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the third quarter of fiscal 2013, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference to 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 2013:

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) (1)
July 2013	18,671	$17.59	—	$224.1
August 2013	6,229,268	17.28	6,211,426	116.8
September 2013	440,616	17.37	430,407	109.3
Total	6,688,555		6,641,833	

(1) In October 2011, the Company's Board of Directors approved a share repurchase program for up to $500 million of Denbury's common stock, which program was expanded by an additional $271.2 million authorized in early November 2012.

Between early October 2011, when we announced the commencement of a common share repurchase program and September 30, 2013, we have repurchased 42.8 million shares of Denbury common stock (approximately 10.6% of our outstanding shares of common stock at September 30, 2011) for $661.9 million, or $15.48 per share. The program has no pre-established ending date and may be suspended or discontinued by our Board of Directors at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

All repurchases of our common stock during the third quarter of 2013 not made under our share repurchase program 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

Item 5. Other Information

None

Table of Contents
Denbury Resources Inc.

Item 6. Exhibits

Exhibit No.	Exhibit
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.

Table of Contents

SIGNATURES

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

	DENBURY RESOURCES INC.
November 7, 2013	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
November 7, 2013	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

Table of Contents
Denbury Resources Inc.

INDEX TO EXHIBITS

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101	Interactive Data Files.