DENBURY RESOURCES INC
Form 10-Q
November 06, 2015

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, 2015
OR

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, 2015
Common Stock, $.001 par value	351,162,058

Denbury Resources Inc.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

	September 30, 2015	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$12,212	$23,153
Accrued production receivable	123,759	181,761
Trade and other receivables, net	118,457	156,955
Derivative assets	199,431	440,359
Other current assets	11,758	10,452
Total current assets	465,617	812,680
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	10,102,698	9,782,337
Unevaluated properties	917,463	918,406
CO_2 properties	1,178,827	1,162,538
Pipelines and plants	2,285,152	2,269,564
Other property and equipment	450,053	468,051
Less accumulated depletion, depreciation, amortization and impairment	(8,252,335)	(4,248,652)
Net property and equipment	6,681,858	10,352,244
Derivative assets	—	66,187
Goodwill	—	1,283,590
Other assets	207,677	213,101
Total assets	$7,355,152	$12,727,802
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$250,514	$394,758
Oil and gas production payable	101,692	128,170
Deferred tax liabilities	7,884	81,727
Current maturities of long-term debt	36,038	35,470
Total current liabilities	396,128	640,125
Long-term liabilities		
Long-term debt, net of current portion	3,321,315	3,535,900
Asset retirement obligations	136,238	126,411
Deferred tax liabilities	1,336,247	2,694,842
Other liabilities	28,892	26,668
Total long-term liabilities	4,822,692	6,383,821
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; 414,322,723 and 411,779,911 shares issued, respectively	414	412
Paid-in capital in excess of par	3,235,266	3,230,418

Retained earnings (accumulated deficit)	(173,892)	3,392,465
Accumulated other comprehensive loss	(157)	(209)
Treasury stock, at cost, 61,373,201 and 58,415,507 shares, respectively	(925,299)	(919,230)
Total stockholders' equity	2,136,332	5,703,856
Total liabilities and stockholders' equity	$7,355,152	$12,727,802

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues and other income				
Oil, natural gas, and related product sales	$290,388	$622,005	$954,749	$1,902,880
CO_2 and helium sales and transportation fees	9,144	11,378	23,268	33,961
Interest income and other income	4,068	4,274	9,926	14,680
Total revenues and other income	303,600	637,657	987,943	1,951,521
Expenses				
Lease operating expenses	113,902	155,198	387,156	488,827
Marketing and plant operating expenses	14,458	15,328	40,358	50,263
CO_2 and helium discovery and operating expenses	1,017	11,434	2,909	22,229
Taxes other than income	25,607	39,966	85,841	136,761
General and administrative expenses	32,907	40,366	117,134	123,011
Interest, net of amounts capitalized of $8,081, $5,862, $25,228 and $17,413, respectively	39,225	44,752	119,187	140,136
Depletion, depreciation, and amortization	121,406	146,560	419,304	435,854
Commodity derivatives expense (income)	(92,028)	(252,265)	(126,178)	(825)
Loss on early extinguishment of debt	—	—	—	113,908
Write-down of oil and natural gas properties	1,760,600	—	3,612,600	—
Impairment of goodwill	1,261,512	—	1,261,512	—
Total expenses	3,278,606	201,339	5,919,823	1,510,164
Income (loss) before income taxes	(2,975,006)	436,318	(4,931,880)	441,357
Income tax provision (benefit)	(730,880)	167,570	(1,431,509)	169,499
Net income (loss)	$(2,244,126)	$268,748	$(3,500,371)	$271,858
Net income (loss) per common share				
Basic	$(6.41)	$0.77	$(10.01)	$0.78
Diluted	$(6.41)	$0.77	$(10.01)	$0.77
Dividends declared per common share	$0.0625	$0.0625	$0.1875	$0.1875
Weighted average common shares outstanding				
Basic	350,052	348,454	349,787	348,993
Diluted	350,052	350,918	349,787	351,347

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$(2,244,126)	$268,748	$(3,500,371)	$271,858
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $11, $11, $32, and $35, respectively	17	18	52	50
Total other comprehensive income	17	18	52	50
Comprehensive income (loss)	$(2,244,109)	$268,766	$(3,500,319)	$271,908

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,	
	2015	2014
Cash flows from operating activities		
Net income (loss)	$(3,500,371)	$271,858
Adjustments to reconcile net income (loss) to cash flows from operating activities		
Depletion, depreciation, and amortization	419,304	435,854
Write-down of oil and natural gas properties	3,612,600	—
Impairment of goodwill	1,261,512	—
Deferred income taxes	(1,432,572)	168,967
Stock-based compensation	22,637	26,104
Commodity derivatives expense (income)	(126,178)	(825)
Receipt (payment) on settlements of commodity derivatives	433,293	(102,255)
Loss on early extinguishment of debt	—	113,908
Amortization of debt issuance costs and discounts	6,810	10,433
Other, net	(7,457)	(5,037)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	57,867	565
Trade and other receivables	37,463	(6,885)
Other current and long-term assets	(1,771)	(370)
Accounts payable and accrued liabilities	(53,124)	(7,195)
Oil and natural gas production payable	(26,478)	(17,225)
Other liabilities	(4,138)	(2,800)
Net cash provided by operating activities	699,397	885,097
Cash flows from investing activities		
Oil and natural gas capital expenditures	(364,948)	(699,012)
Acquisitions of oil and natural gas properties	(21,171)	(1,684)
CO_2 capital expenditures	(21,894)	(38,272)
Pipelines and plants capital expenditures	(25,767)	(47,521)
Purchases of other assets	(5,539)	(6,253)
Net proceeds from sales of oil and natural gas properties and equipment	327	3,011
Other	11,452	808
Net cash used in investing activities	(427,540)	(788,923)
Cash flows from financing activities		
Bank repayments	(1,491,000)	(1,827,000)
Bank borrowings	1,306,000	1,897,000
Repayment of senior subordinated notes	(485)	(997,345)
Premium paid on repayment of senior subordinated notes	—	(101,342)
Proceeds from issuance of senior subordinated notes	—	1,250,000
Costs of debt financing	(1,639)	(17,551)
Common stock repurchase program	(2,692)	(211,356)
Cash dividends paid	(65,422)	(65,241)
Other	(27,560)	(16,090)
Net cash used in financing activities	(282,798)	(88,925)

Net increase (decrease) in cash and cash equivalents	(10,941)	7,249
Cash and cash equivalents at beginning of period	23,153	12,187
Cash and cash equivalents at end of period	$12,212	$19,436

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil 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, 2014 (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, 2015, our consolidated results of operations for the three and nine months ended September 30, 2015 and 2014, and our consolidated cash flows for the nine months ended September 30, 2015 and 2014.

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 (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) 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, 2015 and 2014, there were no adjustments to net income (loss) for purposes of calculating basic and diluted net income (loss) per common share.

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

In thousands	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Basic weighted average common shares outstanding	350,052	348,454	349,787	348,993
Potentially dilutive securities				
Restricted stock, stock options, SARs and performance-based equity awards	—	2,464	—	2,354
Diluted weighted average common shares outstanding	350,052	350,918	349,787	351,347

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Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income (loss) per common share (although all non-performance-based restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the three and nine months ended September 30, 2014, the nonvested restricted stock, stock options, SARs and performance-based equity awards are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, the purchase price that the grantee will pay in the future for stock options, and any estimated future tax consequences recognized directly in equity.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2015	2014	2015	2014
Stock options and SARs	9,118	3,827	9,858	4,343
Restricted stock and performance-based equity awards	4,988	12	3,392	457

Write-Down of Oil and Natural Gas Properties

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as those costs have previously been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly.

As a result of the precipitous and continuing decline in NYMEX oil prices since the fourth quarter of 2014, the rolling first-day-of-the-month average oil price for the preceding 12 months, after adjustments for market differentials by field, has fallen throughout 2015, from $79.55 per Bbl for the first quarter of 2015, to $68.48 per Bbl for the second quarter of 2015, and $56.74 per Bbl for the third quarter of 2015. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months, after adjustments for market differentials by field, was $3.95 per Mcf for the first quarter of 2015, $3.74 per Mcf for the second quarter of 2015, and $3.64 per Mcf for the third quarter of 2015. These falling prices have led to our recognizing full cost pool ceiling test write-downs of $1.8 billion, $1.7 billion and $0.2 billion during the three months ended September 30, 2015, June 30, 2015, and March 31, 2015, respectively.

Impairment of Goodwill

We are required to test goodwill for impairment on an interim basis when we determine that it is more likely than not that the fair value of our reporting unit is less than its carrying amount. Our enterprise value (combined market capitalization plus a control premium of 10% and the fair value of our long-term debt) declined by approximately $2.5 billion between June 30 and September 30, 2015; therefore, we concluded that a goodwill impairment test was required to be performed in the third quarter.

For the goodwill impairment test, we compared the fair value of the reporting unit (enterprise value) to the fair value of its assets and liabilities. Oil and natural gas reserves, which represent the most significant assets requiring valuation, were estimated using the expected present value of future net cash flows method based on September 30, 2015, NYMEX oil and natural gas futures prices for the next five years, adjusted for current price differentials. In addition to future oil and natural gas pricing, the most significant assumptions impacting the projections of future net cash flows include projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, risk adjustment factors applied to probable and possible oil and natural gas reserve cash flows, projected recovery factors of oil and natural gas reserves, and a weighted average cost of capital discount rate applied to all net cash flows. Because the fair value of the reporting unit (enterprise value) did not exceed the fair value of assets and liabilities, we recorded a goodwill impairment charge of $1.3 billion during the three months ended September 30, 2015, to fully impair the carrying value of our goodwill. Approximately $1.0 billion of the $1.3 billion goodwill balance was associated with the March-2010 merger with Encore Acquisition Company.

Recent Accounting Pronouncements

Debt Issuance Costs. In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-03, Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 requires debt issuance costs related to a recognized debt liability to be presented as a direct reduction of the carrying amount of that debt in the balance sheet, consistent with the presentation of debt discounts. The amendments in this ASU are effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years, and early adoption is permitted. Entities will be required to apply the guidance on a retrospective basis to each period presented as a change in accounting principle. In August 2015, the FASB issued ASU 2015-15, Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-15") which amends ASU 2015-03 to clarify the presentation and subsequent measurement of debt issuance costs associated with line of credit arrangements, such that entities may continue to apply current practice. The adoption of ASU 2015-03 and 2015-15 are currently not expected to have a material effect on our consolidated financial statements, other than balance sheet reclassifications.

Revenue Recognition. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). ASU 2014-09 amends the guidance for revenue recognition to replace numerous, industry-specific requirements. The core principle of the ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU implements a five-step process for customer contract revenue recognition that focuses on transfer of control, as opposed to transfer of risk and rewards. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers ("ASU 2015-14") which amends ASU 2014-09 and delays the effective date for public companies, such that the amendments in the ASU are effective for reporting periods beginning after December 15, 2017, and early adoption will be permitted for periods beginning after December 15, 2016. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. Management is currently assessing the impact the adoption of ASU 2014-09 and ASU 2015-14 will have on our consolidated financial statements.

Note 2. Long-Term Debt

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

In thousands	September 30, 2015	December 31, 2014
Bank Credit Agreement	$210,000	$395,000
6 % Senior Subordinated Notes due 2021	400,000	400,000
5½% Senior Subordinated Notes due 2022	1,250,000	1,250,000

4 % Senior Subordinated Notes due 2023	1,200,000	1,200,000
Other Subordinated Notes, including premium of $8 and $11, respectively	2,258	2,746
Pipeline financings	214,179	220,583
Capital lease obligations	80,916	103,041
Total	3,357,353	3,571,370
Less: current obligations	(36,038)	(35,470)
Long-term debt and capital lease obligations	$3,321,315	$3,535,900

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, and the guarantees of the notes are full and unconditional and joint and several; any subsidiaries of DRI that are not subsidiary guarantors of certain of such notes are minor subsidiaries.

Bank Credit Facility

In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with a current borrowing base of $2.6 billion and aggregate lender commitments of $1.6 billion. Our obligations under the Bank Credit Agreement are guaranteed jointly and severally by each subsidiary of DRI that is 100% owned, directly or indirectly, by DRI. The Bank Credit Agreement is secured by (1) a significant portion of our proved oil and natural gas properties, which are held through DRI's restricted subsidiaries; (2) the pledge of equity interests of such subsidiaries; and (3) a pledge of commodity derivative agreements of DRI and such subsidiaries (as applicable). Loans under the Bank Credit Agreement mature in December 2019. The weighted average interest rate on borrowings outstanding as of September 30, 2015, under the Bank Credit Agreement was 1.8%. The undrawn portion of the aggregate lender commitments under the Bank Credit Agreement is subject to a commitment fee ranging from 0.3% to 0.375% per annum. As of September 30, 2015, we were in compliance with all debt covenants under the Bank Credit Agreement.

Borrowing base redeterminations under our Bank Credit Agreement occur annually, and with our last such redetermination having been completed in early-May 2015, our next scheduled redetermination is set for May 2016. The lenders are entitled, at their election, to request one interim redetermination between annual scheduled redeterminations; however, as of November 4, 2015, there has been no such request to do so. In connection with the borrowing base redetermination completed in early-May 2015, we elected to maintain our aggregate lender commitments at $1.6 billion; however, due to a reduction in oil prices used by our lenders in determining the borrowing base value of our proved reserves attributable to our oil and natural gas properties, our borrowing base was reduced from the previous level of $3.0 billion to $2.6 billion. Because we continue to maintain a significant cushion between our borrowing base and the aggregate lender commitments, and because we had significant availability with respect to our aggregate lender commitments as of September 30, 2015, the borrowing base reduction has no impact on our liquidity.

In conjunction with the May 2015 redetermination, we also entered into the First Amendment to the Bank Credit Agreement (the "First Amendment") to restructure certain financial covenants in 2016, 2017, and 2018 in order to provide more flexibility in managing our balance sheet and managing the credit extended by our lenders if oil prices remain low over the next several years. The covenant changes included in the First Amendment were as follows:

- In 2016 and 2017, suspend the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant of 4.25 to 1.0 and replace it with a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 2.5 to 1.0 during the same time period. Currently, only debt under our Bank Credit Agreement would be considered consolidated senior secured debt for purposes of this ratio.
- Beginning in the first quarter of 2018, reinstate the ratio of consolidated total net debt to consolidated EBITDAX covenant utilizing an annualized EBITDAX amount for the first quarter of 2018 and building to a trailing four quarters by the end of 2018, with the maximum permitted ratios being 6.0 to 1.0 for the first quarter ended March 31,

2018, 5.5 to 1.0 for the second quarter ended June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ended September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ended March 31, 2019.

- In 2016 and 2017, institute a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 2.25 to 1.0.

The restructuring of covenants through the First Amendment was executed in consideration of a fee paid to the lenders. The First Amendment has no impact on the current ratio financial performance covenant, which will remain in place in 2015 and beyond. All of the above descriptions of financial covenants are qualified by the express language and defined terms contained in the Bank Credit Agreement.

2014 Issuance of 5½% Senior Subordinated Notes due 2022

In April 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes"), which were sold at par. The net proceeds, after issuance costs, of $1.23 billion were used to repurchase or redeem our outstanding $996.3 million of 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes") (see 2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020 below) and to pay down a portion of outstanding borrowings under our previous bank credit agreement.

2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020

During the second quarter of 2014, we repurchased and redeemed the entire $996.3 million outstanding principal amount of our 8¼% Notes using a portion of the proceeds from the issuance of the 5½% Notes. We recognized a $113.9 million loss associated with the debt repurchases during the second quarter of 2014, which loss consists of both premium payments made to repurchase or redeem the 8¼% Notes and the elimination of unamortized debt issuance costs related to these notes. The loss is included in our Unaudited Condensed Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Unaudited Condensed Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

Note 3. Income Taxes

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. As of September 30, 2015, we had $37.0 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of a new tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized a tax valuation allowance of $30.5 million during the second quarter of 2015 to reduce the carrying value of our deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized. Our effective tax rate for the three months ended September 30, 2015, was lower than our estimated statutory rate, as a significant portion of the book value of our goodwill impaired during the quarter had no related tax basis. Therefore, no corresponding deferred tax benefit was recognized related to that portion of the goodwill impairment. Our effective tax rate for the nine months ended September 30, 2015, was further impacted by the tax valuation allowance discussed above, which also reduced the net deferred tax benefit recognized.

Note 4. Stockholders' Equity

During the second quarter of 2015, we reduced the number of shares of our common stock reported as outstanding by 1,430,819 shares (approximately 0.4% of our outstanding shares at March 31, 2015). This reduction was the result of a correction to properly reflect the number of shares actually issued in the merger with Encore Acquisition Company ("Encore") in March 2010. The stock and cash consideration originally issued and paid in the Encore merger was valued at $3.0 billion, which would have been reduced by $22.1 million for this share correction. As a result, we recorded adjustments to our Unaudited Condensed Consolidated Balance Sheet to reflect a decrease in consideration paid in the Encore merger through a reduction of "Goodwill" ($22.1 million), offset by a reduction in an equal amount of the Company's stockholders' equity ($22.1 million). We determined that this correction in outstanding shares (1) had no impact on net income (loss) for the second quarter of 2015, our estimated results of operations for the year ending December 31, 2015, or for any prior period, and (2) was not material to our consolidated balance sheet, statement of cash flows, or basic or diluted earnings per common share for the second quarter of 2015, or for any prior period, and therefore we recorded the cumulative effect of correcting these items during the three months ended June 30, 2015.

Dividends

In all four quarters of 2014 and in each of the first three quarters of 2015, the Company's Board of Directors declared quarterly cash dividends of $0.0625 per common share, or an annual rate of $0.25 per common share. On September 21, 2015, in light of the continuing low oil price environment and its desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend, after payment of our third quarter dividend on September 29, 2015. By suspending the dividend, we will free up cash which can be directed to other uses. Dividends totaling $65.4 million and $65.2 million were paid to stockholders during the nine months ended September 30, 2015 and 2014, respectively.

Stock Repurchase Program

On September 21, 2015, the Company's Board of Directors reinstated the ability to repurchase shares under our share repurchase program, which authorization was suspended in November of 2014. During the three months ended September 30, 2015, we repurchased 2.7 million shares of Denbury common stock for $6.9 million, and in October 2015 we repurchased an additional 1.7 million shares of Denbury common stock for $4.8 million. During the three months ended March 31, 2014, we repurchased 12.4 million shares of Denbury common stock for $200.4 million. As of November 4, 2015, $210.1 million remains authorized for use under this repurchase program. Our share repurchases are based on various parameters including, but not limited to, the price of our common stock, oil prices, free cash flow, our leverage or other funding sources available to us. There is no requirement that the remaining balance under the program be utilized, and there is no set expiration date for the repurchase program.

Employee Stock Purchase Program

We previously provided for an Employee Stock Purchase Plan (the "Plan") in which funds from eligible employees, together with Company contributions, were used to purchase previously unissued Denbury common stock or treasury stock that we purchased in the open market for that purpose, in either case, based on the market value of our common stock at the end of each quarter. The Plan was terminated, effective at the end of the offering period ended on March 31, 2015, as all of the previously authorized shares reserved for issuance under the Plan had been issued.

Note 5. Commodity 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 settlements of expired contracts, are shown under "Commodity derivatives expense (income)" in our Unaudited Condensed Consolidated Statements of Operations.

Historically, we have entered 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 and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. 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. For the past several years, we have generally hedged a substantial portion of our forecasted production over an approximately 18 month to two year future period, as we believed it was beneficial to protect our future cash flows at then-projected oil prices for those future periods. However, during the significant and rapid decline in oil prices in the fourth quarter of 2014 and the first quarter of 2015, we deferred entering into new derivative contracts; we entered into limited oil hedging positions during the second quarter of 2015 covering the second and third quarters of 2016 as a result of the slight recovery in oil prices; and we have not entered into any additional hedges since the second quarter of 2015. Consequently, we currently have less of our production hedged and for a shorter future time period than we have generally had over the last several years.

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 (or affiliates of such lenders). As of September 30, 2015, 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.

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The following table summarizes our commodity derivative contracts as of September 30, 2015, none of which are classified as hedging instruments in accordance with the Financial Accounting Standards Board Codification ("FASC") Derivatives and Hedging topic:

Months	Index Price	Volume [2]	Contract Prices [1] Range [3]		Weighted Average Price Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2015 Enhanced Swaps [4]								
Oct – Dec	NYMEX	12,000	$ 91.15	– 94.00	$92.42	$68.00	$—	$—
Oct – Dec	LLS	8,000	93.80	– 96.50	94.94	68.00	—	—
2015 Three-Way Collars [5]								
Oct – Dec	NYMEX	10,000	$ 85.00	– 102.00	$—	$68.00	$85.00	$99.00
Oct – Dec	LLS	8,000	88.00	– 104.25	—	68.00	88.00	100.99
2016 Enhanced Swaps [4]								
Jan – Mar	NYMEX	12,000	$ 90.65	– 93.35	$92.43	$68.00	$—	$—
Jan – Mar	LLS	8,000	93.70	– 95.45	94.81	68.50	—	—
Apr – June	NYMEX	2,000	90.35	– 90.35	90.35	68.00	—	—
Apr – June	LLS	6,000	93.30	– 93.50	93.38	70.00	—	—
2016 Fixed-Price Swaps								
Apr – June	NYMEX	11,500	$ 60.30	– 63.75	$61.84	$—	$—	$—
Apr – June	LLS	3,500	64.20	– 66.15	64.99	—	—	—
2016 Three-Way Collars [5]								
Jan – Mar	NYMEX	10,000	$ 85.00	– 101.25	$—	$68.00	$85.00	$99.85
Jan – Mar	LLS	6,000	88.00	– 103.15	—	68.00	88.00	102.10
Apr – June	NYMEX	2,000	85.00	– 95.50	—	68.00	85.00	95.50
Apr – June	LLS	2,000	88.00	– 98.25	—	70.00	88.00	98.25
2016 Collars								
Apr – June	NYMEX	5,000	$ 55.00	– 72.25	$—	$—	$55.00	$71.01
Apr – June	LLS	2,000	58.00	– 73.00	—	—	58.00	73.00
July – Sept	NYMEX	4,500	55.00	– 72.65	—	—	55.00	71.22
July – Sept	LLS	3,000	58.00	– 74.30	—	—	58.00	73.85
Natural Gas Contracts:								
2015 Collars								
Oct – Dec	NYMEX	8,000	$ 4.00	– 4.53	$—	$—	$4.00	$4.51

(1) Contract prices are stated in $/Bbl and $/MMBtu for oil and natural gas contracts, respectively.
(2) Contract volumes are stated in Bbls/d and MMBtus/d for oil and natural gas contracts, respectively.
(3) Ranges presented for fixed-price swaps and enhanced swaps represent the lowest and highest fixed prices of all open contracts for the period presented. For collars and three-way collars, ranges represent the lowest floor price and highest ceiling price for all open contracts for the period presented.

(4) An enhanced swap is a fixed-price swap contract combined with a sold put feature (at a lower price) with the same counterparty. The value associated with the sold put is used to increase or enhance the fixed price of the swap. At the contract settlement date, (1) if the index price is higher than the swap price, we pay the counterparty the difference between the index price and swap price for the contracted volumes, (2) if the index price is lower than the swap price but at or above the sold put price, the counterparty pays us the difference between the index price and the swap price for the contracted volumes and (3) if the index price is lower than the sold put price, the counterparty pays us the difference between the swap price and the sold put price for the contracted volumes.

(5) A three-way collar is a costless collar contract combined with a sold put feature (at a lower price) with the same counterparty. The value received for the sold put is used to enhance the contracted floor and ceiling price of the related collar. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price for the contracted volumes, (2) if the index price is between the floor and ceiling price, no settlements occur, (3) if the index price is lower than the floor price but at or above the sold put price, the counterparty pays us the difference between the index price and the floor price for the contracted volumes and (4) if the index price is lower than the sold put price, the counterparty pays us the difference between the floor price and the sold put price for the contracted volumes.

Note 6. Fair Value Measurements

The FASC Fair Value Measurement 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"). 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 income approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

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

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing and fixed-price swaps that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The fixed-price swap features of our enhanced swaps are valued using a discounted cash flow model based upon forward commodity price curves. Our costless collars and the sold put features of our enhanced oil swaps and three-way 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, 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.

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Level 3 – Pricing inputs include significant inputs that are generally less observable. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At September 30, 2015, instruments in this category include non-exchange-traded enhanced swaps, costless collars and three-way collars that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The valuation models utilized for enhanced swaps, costless collars and three-way collars are consistent with the methodologies described above; however, the implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. An increase or decrease of 100 basis points in the implied volatility inputs utilized in our fair value measurement would result in a change of approximately $0.1 million in the fair value of these instruments as of September 30, 2015.

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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.

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, 2015				
Assets:				
Oil and natural gas derivative contracts – current	$—	$116,557	$82,874	$199,431
Total Assets	$—	$116,557	$82,874	$199,431
December 31, 2014				
Assets:				
Oil and natural gas derivative contracts – current	$—	$283,238	$157,121	$440,359
Oil and natural gas derivative contracts – long-term	—	34,862	31,325	66,187
Total Assets	$—	$318,100	$188,446	$506,546

Since we do not apply hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in "Commodity derivatives expense (income)" in the accompanying Unaudited Condensed Consolidated Statements of Operations.

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2015	2014	2015	2014
Fair value of Level 3 instruments, beginning of period	$112,358	$(39,116)	$188,446	$6,709
Fair value adjustments on commodity derivatives	21,089	61,411	38,872	15,586
Receipts on settlements of commodity derivatives	(50,573)	—	(144,444)	—
Fair value of Level 3 instruments, end of period	$82,874	$22,295	$82,874	$22,295
The amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at the reporting date	$15,332	$61,411	$25,456	$15,586

We utilize an income approach to value our Level 3 enhanced swaps, costless collars and three-way collars. 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. The following table details fair value inputs related to implied volatilities utilized in the valuation of our Level 3 oil derivative contracts:

	Fair Value at 9/30/2015 (in thousands)	Valuation Technique	Unobservable Input	Volatility Range
Oil derivative contracts	$82,874	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after September 30, 2015	30.2% – 37.5%

Other Fair Value Measurements

The carrying value of loans under our Bank Credit Agreement approximate fair value, as they are 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 long-term debt using observable market data. The fair values of our senior subordinated notes are based on quoted market prices, resulting in an estimated fair value of our debt as of September 30, 2015 and December 31, 2014, excluding pipeline financing and capital lease obligations, of $1,855.0 million and $2,938.6 million, 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 regulatory proceedings incidental to our businesses. We are also subject to audits for various taxes (income, sales and use, and severance) in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. 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. Although a single or multiple adverse rulings or settlements could possibly have a material adverse effect on our finances, we only accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

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. Our remediation efforts with respect to such release were completed during the fourth quarter of 2013; however, we continue to monitor the impacted area to confirm the effectiveness of the remediation efforts. Virtually all of our total recorded cost of $130.8 million has been incurred.

We maintain insurance policies to cover certain costs, damages and claims related to releases of well fluids and remediation. We received a $25.0 million cost reimbursement in October 2014 related to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess liability insurance coverage, and an additional $4.5 million cost reimbursement in August 2015 from our insurance carrier providing well control coverage. We have not reached any agreement with our remaining carriers as to further reimbursements, but given our belief that under our policies we are entitled to reimbursement of between approximately one-third and two-thirds of our total costs, we have filed suit to pursue further reimbursements, the ultimate outcome of which cannot be predicted.

In March 2015, Evolution Petroleum Company ("Evolution"), the parent of the entity which sold Denbury Onshore, LLC ("Denbury Onshore") its original interest in Delhi Field, filed an amended petition in a lawsuit which has been pending in the Texas district court in Houston since December 2013. Originally, that lawsuit involved ongoing disputes between Denbury Onshore and Evolution regarding the terms of the purchase documents under which Denbury Onshore bought its original Delhi Field interest, including disputes regarding allocation of costs in determining "payout" as defined in the agreements, and the extent and terms of assignment of reversionary interests in the unit back to Evolution following payout, along with related contractual terms. The amended petition added allegations of negligence and gross negligence against Denbury Onshore in connection with the June 2013 Delhi Field release, and for the first time estimated its damages attributable to its allegations in the case as exceeding $200 million.

The amended petition also adds a claim for unspecified punitive damages. There has only been limited discovery in the case to date, and Evolution has not specified the basis for the amount of its claimed damages estimate. The case is currently set for trial in April 2016. We believe Evolution's claims with respect to this matter are without merit and intend to vigorously defend against them and pursue our rights under the purchase documents.

Note 8. Additional Balance Sheet Details

Trade and Other Receivables, Net

In thousands	September 30, 2015	December 31, 2014
Commodity derivatives settlement receivables	$53,103	$59,755
Trade accounts receivable, net	35,495	45,407
Federal income tax receivable, net	—	37,652
Other receivables	29,859	14,141
Total	$118,457	$156,955

Accounts Payable and Accrued Liabilities

In thousands	September 30, 2015	December 31, 2014
Accrued interest	$45,844	$48,255
Accrued compensation	43,864	62,513
Accrued taxes other than income	41,253	39,816
Accrued lease operating expenses	36,609	56,798
Accounts payable	34,661	64,604
Accrued exploration and development costs	14,836	90,939
Other	33,447	31,833
Total	$250,514	$394,758

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, 2014 (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

Denbury is an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

Oil Price Decline and Impact on Our Business. Oil prices generally constitute the single largest variable in our operating results. Although oil prices have historically been volatile, during the fourth quarter of 2014 and continuing throughout 2015, oil prices have dropped significantly, with NYMEX prices declining from $107 per Bbl in June 2014 to less than $44 per Bbl in March 2015, and ending September 2015 at $45 per Bbl. The following charts illustrate the fluctuations in our realized oil and natural gas prices, excluding the impact of commodity derivative settlements, during 2014 and the first three quarters of 2015.

	Three Months Ended						
Average realized prices	3/31/2014	6/30/2014	9/30/2014	12/31/2014	3/31/2015	6/30/2015	9/30/2015
Oil price per Bbl	$97.69	$100.04	$94.78	$70.80	$46.02	$56.92	$45.74
Natural gas price per Mcf	4.71	4.39	3.55	3.54	2.54	2.44	2.40

In response to the decline in oil prices, we have made adjustments to our business to preserve our financial strength and flexibility. These adjustments include: (1) reducing our original projected 2015 development capital spending to less than half of 2014 levels, and further reducing our projected development capital spending by an additional 20% during 2015, (2) reducing costs and identifying new innovation and improvement ideas for our fields, which has resulted in meaningful decreases to date in most categories of our lease operating expenses and general and administrative expenses, and cost savings on capital projects, (3) modifying certain of our bank covenants applicable to the 2016, 2017 and 2018 periods to mitigate concern around our ability to access our bank credit line if oil prices remain low for an extended period of time, and (4) most recently, suspending our quarterly cash dividend after payment of our third quarter dividend on September 29, 2015 (see Capital Resources and Liquidity – Dividends below for further discussion), which will free up approximately $22 million of cash each quarter that was historically paid out in dividends, which can be directed to other uses including, among other things, debt reduction, increases in capital spending, or

repurchases of shares of Denbury common stock. As a result of these adjustments and the commodity hedges we have in place for 2015, we have generated cash flow from operations in excess of capital expenditures and dividends, with which we have been able to reduce our credit facility borrowings from $395.0 million at December 31, 2014, to $210.0 million at September 30, 2015.

Operating Highlights. Our financial results have been significantly impacted by the decrease in realized oil prices as highlighted above, which decreased from an average of $94.78 per Bbl in the third quarter of 2014 to $45.74 in the third quarter of 2015. During the third quarter of 2015, we recognized a net loss of $2.2 billion, or $6.41 per diluted common share, compared to net income of $268.7 million, or $0.77 per diluted common share, during the third quarter of 2014. The change in income between the third quarter of 2015 and 2014 was primarily due to a full cost pool ceiling test write-down of our oil and natural gas properties totaling $1.8 billion ($1.1 billion net of tax) (see Write-Down of Oil and Natural Gas Properties below) and a goodwill impairment charge totaling $1.3 billion ($1.2 billion net of tax) (see Impairment of Goodwill below). Other significant changes between the third quarter of 2015 and 2014 were a $331.6 million (53%) decline in our oil and natural gas revenues between the periods, which was primarily oil-price related, and a $160.2 million decrease in commodity derivatives income, offset in part by a $41.3 million (27%) reduction in lease operating expense, a $25.2 million (17%) decrease in depletion, depreciation, and amortization, a $14.4 million (36%) decrease in taxes other than income, and a $7.5 million (18%) decrease in general and administrative expenses. The $160.2 million decrease in commodity derivatives income between the two periods was due to a $345.8 million loss associated with noncash fair value commodity adjustments, offset in part by a $185.6 million increase in income from settlements of derivative contracts.

We generated $272.7 million of cash flows from operating activities in the third quarter of 2015, compared to $289.0 million in the second quarter of 2015 and $340.4 million in the prior-year third quarter. Despite sequential-quarter declines in oil prices which contributed to a $76.5 million decrease in oil and natural gas revenues, our cash flows from operations decreased by only $16.3 million between the second and third quarters of 2015, the largest reason for which related to positive changes in derivative settlements, as well as reductions in lease operating expenses, taxes other than income, and general and administrative expenses. The decrease in cash flows from operations between the third quarter of 2015 and 2014 was due primarily to lower oil prices, which caused a decrease in oil revenues, partially offset by significant positive changes in derivative settlements and, to a lesser extent, reductions in lease operating expenses, taxes other than income, CO_2 and helium discovery and operating expenses, general and administrative expenses, and interest expense. Despite recent significant decreases in oil prices, based upon oil futures prices at the end of October 2015, we currently expect that for full-year 2015, we will generate significant cash flow from operations above and beyond our capital expenditures and dividends.

During the third quarter of 2015, our oil and natural gas production, which was 95% oil, averaged 71,410 BOE/d, compared to an average of 73,810 BOE/d produced during the third quarter of 2014 and 73,716 BOE/d during the second quarter of 2015. Oil production from our tertiary operations during the third quarter of 2015 decreased 793 Bbls/d (2%) compared to tertiary production levels in the same period in 2014, and decreased 1,750 Bbls/d (4%) when comparing tertiary production between the third quarter of 2015 and second quarter of 2015. The change in our total production between the comparative third quarters was primarily a result of natural production declines at our mature tertiary properties in the Gulf Coast region, a decline at Cedar Creek Anticline Field, a temporary production decline at Tinsley Field, and a contractual reversionary interest assignment at Delhi Field, offset in part by production increases at Oyster Bayou Field and Bell Creek Field. On a sequential quarterly basis, the production decline was primarily due to the decline at Tinsley and Cedar Creek Anticline fields, partially offset by a production increase at Bell Creek Field. See Results of Operations – Production for further discussion.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, was $45.74 per Bbl during the third quarter of 2015, a decrease of 52% compared to $94.78 per Bbl realized during the third quarter of 2014 and a decrease of 20% compared to $56.92 per Bbl realized during the second quarter of 2015. The oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) was $0.96 per Bbl below NYMEX prices in the third quarter of 2015, compared to a negative $2.53 per Bbl NYMEX differential in the third quarter of 2014, and a negative $0.89 per Bbl NYMEX differential in the second quarter of 2015. The improvement in our oil price differential in comparison to its level in the third quarter of 2014 was principally due to improvement in the Rocky Mountain region discount relative to NYMEX oil prices.

One of our primary focuses in 2014 and 2015 has been to reduce costs throughout the organization, through a number of internal initiatives. Our efforts have proven successful, and our lease operating expenses in the third quarter of 2015, normalized to exclude insurance and other special reimbursements (see Results of Operations – Production Expenses for further discussion), were less than $19.50 per BOE, a decrease of 14% when compared to per-BOE levels in the fourth quarter of 2014. In addition, our recurring lease operating expenses per BOE decreased each sequential quarter in 2014 and in the first three quarters of 2015 and decreased a total of 26% between the fourth quarter of 2013 and the third quarter of 2015, with decreases realized in most categories of lease operating expenses, the most significant of which included workover costs, power costs, CO_2 costs, and certain third-party contractor and vendor costs. On a sequential-quarter basis, lease operating expenses per BOE, excluding insurance and other reimbursements, decreased slightly between the second quarter of 2015 and the third quarter of 2015, and our goal is to continue to find efficiencies in both capital project costs and per-barrel operating costs.

Write-Down of Oil and Natural Gas Properties. Due to a continued decline in the first-day-of-the-month average oil and natural gas price for each quarterly 12-month rolling period in 2015, we recognized full cost pool ceiling test write-downs of $1.8 billion, $1.7 billion and $0.2 billion during the three months ended September 30, 2015, June 30, 2015, and March 31, 2015, respectively. See Note 1, Basis of Presentation – Write-Down of Oil and Natural Gas Properties, to the Unaudited Condensed Consolidated Financial Statements, and Results of Operations – Write-Down of Oil and Natural Gas Properties, for additional information regarding the ceiling test.

Impairment of Goodwill. Based on the results of our goodwill impairment test performed during the third quarter of 2015, we recorded a goodwill impairment charge of $1.3 billion to fully impair the carrying value of our goodwill. Between June 30 and September 30, 2015, the fair value of our reporting unit (enterprise value) declined at a rate greater than the decline in NYMEX oil futures prices, which is a significant factor impacting the value of our oil and natural gas reserves, leading to the goodwill impairment. See Note 1, Basis of Presentation – Impairment of Goodwill, to the Unaudited Condensed Consolidated Financial Statements, and Results of Operations – Impairment of Goodwill below, for additional information regarding the goodwill impairment test.

Impact of Commodity Price Decline on Proved Oil and Natural Gas Reserves Quantities. Declines in commodity prices may materially impact estimated quantities of proved reserves, as certain reserves may reach the point at which they become uneconomic to produce earlier than they would otherwise. The SEC requires proved reserves to be determined based on average first-day-of-the-month oil and natural gas prices for the trailing 12-month period. Using these prices, our total proved reserves at December 31, 2014, were 437.7 MMBOE, of which 83% was oil and 17% was natural gas. During the first nine months of 2015, the average oil price used in estimating our proved reserves declined from $91.89 per Bbl at December 31, 2014, to $56.74 per Bbl at September 30, 2015, and for natural gas declined from $4.30 per Mcf at December 31, 2014, to $3.64 per Mcf at September 30, 2015. These oil and natural gas price changes resulted in an estimated decline of approximately 6% (25 MMBOE) in our proved reserves from December 31, 2014, through September 30, 2015. If prices for the fourth quarter of 2015 approximate recent commodity futures prices, the average NYMEX prices used to estimate our proved reserves at December 31, 2015, would likely decrease further, to approximately $50 per Bbl for oil and $2.75 per Mcf for natural gas. Based on these additional estimated price declines, it is reasonably likely that we could experience further negative revisions in our proved oil and natural gas reserves due to price declines. Our year-end reserves are still being evaluated, and it is therefore difficult to quantify the magnitude of any additional negative reserve revisions due to price; however, we currently expect such negative reserve revisions to be less than 10% of our proved reserve quantities at September 30, 2015. This amount could potentially be higher if natural gas prices were to decrease to a level that would indicate our 61.3 MMBOE of proved natural gas reserves at Riley Ridge were determined to be uneconomic. The actual fourth quarter 2015 reserve revision could vary from the estimated range of revisions for several reasons, including differences in actual commodity prices from commodity futures prices and changes in oil and natural gas price differentials, forecasted production rates, forecasted operating and capital costs, changes in development plans, and other key assumptions included within the estimate of proved oil and natural gas reserves.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability for borrowings under our bank credit facility. Our business is capital intensive, and it is common for oil and natural gas companies our size to reinvest most or all of their cash flow into developing new assets. During 2014 and the first three quarters of 2015, we managed our expenditures such that our cash flow from operations more than covered our capital expenditures and dividends, and based upon oil futures prices at the end of October 2015, we currently expect to generate cash flow from operations for full-year 2015 above and beyond our capital expenditures and dividends. Our cash flow from operations during the nine months ended September 30, 2015 was $699.4 million, which was $321.5 million higher than our incurred development capital expenditures and dividends during the first nine months of the year. We used this excess cash flow from operations primarily to reduce debt, acquire oil and gas properties, and cover working capital outflows, including cash outflows to cover accruals for capital items as of December 31, 2014. In future periods, we currently expect that we would use excess cash flow for, among other things, increases in capital spending, debt repayment or repurchases, or stock repurchases.

As discussed in the Overview above, we have been proactive in adjusting our 2015 capital spending and dividend plans in connection with the current lower oil price environment. We project that we will have adequate capital resources and liquidity for the foreseeable future because (1) we have significant borrowing capacity on our bank credit facility and significant cushion between our current $2.6 billion borrowing base and the $1.6 billion of commitments we have asked the banks to extend to us (see Note 2, Long-Term Debt, and Bank Credit Facility below); (2) we have commodity derivative contracts in place to cover a portion of our forecasted oil production for the fourth quarter of 2015 and the first half of 2016 that will lessen the impact of the current lower oil price environment (see Note 5, Commodity Derivative Contracts, to the Unaudited Condensed Consolidated Financial Statements for further details regarding the prices and volumes of our commodity derivative contracts); (3) generally, we plan to fund our projected capital expenditures with cash flows from operations; (4) we believe that we can significantly reduce our capital expenditures for some time, as we have done in 2015, and still maintain relatively flat or slightly lower production levels as a result of the unique characteristics of CO_2 EOR operations; and (5) the maturity dates of all but a minor amount of our senior subordinated notes occur approximately six or more years in the future and carry attractive fixed interest rates ranging between 4 % and 6 %.

If oil prices remain at relatively low levels beyond 2015, our cash flows from operations will likely be significantly lower than current levels, as our commodity derivative contracts presently in place for 2016 principally cover production during the first half of the year and cover significantly less forecasted oil production at lower prices than our 2015 contracts. Therefore, we continue to focus on reducing our operating and administrative costs so as to preserve as much of our profit margin as possible in this lower oil price environment, and if this low oil price environment persists, we intend to continue to make adjustments to our capital spending plans to preserve our financial health. Fortunately, some of our costs, such as CO_2 purchases and production taxes, adjust proportionally with changes in the price of oil. We also expect that our cost of services and equipment will continue to come down in this lower oil price environment, but this likely will not reflect as large of a percentage decrease as the decrease in the price of oil. As we have done up to this point in 2015, we believe that we can reduce capital spending and maintain production at relatively flat or slightly lower production levels for some time.

Capital Spending. During 2015, we reduced our anticipated full-year 2015 capital budget, excluding acquisitions, from $550 million to $475 million, comprised of a $95 million reduction in development spending, partially offset by a $20 million increase in other capitalized items. Our $475 million budget includes approximately $105 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods. This combined 2015 capital budget amount, excluding acquisitions, is comprised of the following:

- $225 million allocated for tertiary oil field expenditures;
- $100 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $30 million to be spent on CO_2 sources;
- $15 million for pipeline construction; and
- $105 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, 2015, we incurred capital expenditures of $312.5 million, excluding 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 2015 and our current production forecast, we currently anticipate that our 2015 cash flows from operations will be in excess of our combined 2015 capital budget and dividend payments. During the first nine months of 2015, we used excess cash flow from operations to pay down borrowings on our bank credit facility, with a total reduction of $185.0 million from the level outstanding as of December 31, 2014. If prices were to decrease further from October 2015 levels, or changes in operating results were to cause us to have a significant reduction in fourth quarter 2015 operating cash flows, we could reduce our capital expenditures; however, we currently have ample availability on our bank credit facility to cover any potential foreseeable shortfall. If we further reduce our capital spending due to lower cash flows, any sizeable reduction could lower our anticipated production levels in future years. Based on current 2016 oil futures prices as of late-October 2015 and our projections at this time, we currently anticipate that our 2016 capital budget, excluding acquisitions, will be between $300 million and $350 million.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the nine months ended September 30, 2015 and 2014:

In thousands	Nine Months Ended September 30, 2015	2014
Capital expenditures by project		
Tertiary oil fields	$133,439	$442,810
Non-tertiary fields	75,199	186,708
Capitalized interest and internal costs (1)	72,235	67,437
Oil and natural gas capital expenditures	280,873	696,955
CO_2 pipelines	10,135	24,612
CO_2 sources (2)	17,686	37,502
CO_2 capitalized interest and other	3,816	2,831
Capital expenditures, before acquisitions	312,510	761,900
Acquisitions of oil and natural gas properties	22,755	1,683
Capital expenditures, total	$335,265	$763,583

(1) Includes capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.
(2) Includes capital expenditures related to the Riley Ridge gas processing facility.

For the first nine months of 2015 and 2014, our capital expenditures and property acquisitions were fully funded with cash flows from operations.

Bank Credit Facility. Borrowing base redeterminations under our Bank Credit Agreement occur annually, and with our last such redetermination having been completed in early-May 2015, our next scheduled redetermination is set for May 2016. The lenders are entitled, at their election, to request one interim redetermination between annual scheduled redeterminations; however, as of November 4, 2015, there has been no such request to do so. In connection with the borrowing base redetermination completed in early-May 2015, we elected to maintain our aggregate lender commitments at $1.6 billion; however, due to a reduction in oil prices used by our lenders in determining the borrowing base value of our proved reserves attributable to our oil and natural gas properties, our borrowing base was reduced from the previous level of $3.0 billion to $2.6 billion. Because we continue to maintain a $1.0 billion cushion between our borrowing base and the aggregate lender commitments, even after this borrowing base reduction, and because we had availability of $1.4 billion with respect to our aggregate lender commitments as of September 30, 2015, this borrowing base reduction has no impact on our liquidity.

For 2015, our Bank Credit Agreement contains certain restrictive covenants, plus two principal financial performance covenants to maintain (1) a ratio of consolidated total net debt to consolidated EBITDAX of not more than 4.25 to 1.0 and (2) a ratio of consolidated current assets to consolidated current liabilities ("current ratio") not less than 1.0. For these financial performance covenant calculations as of September 30, 2015, our ratio of consolidated total net debt to consolidated EBITDAX was 2.86 to 1.0, and our current ratio was 4.56. We currently project to continue to be in compliance with these covenants through the remainder of 2015, and based upon our current forecasted levels of production and costs, assuming oil and natural gas prices remain at or above commodity futures prices as of late-October 2015 (approximating $50 per Bbl during 2016), we would also anticipate continuing to be in compliance with our bank covenants during 2016.

In conjunction with the May 2015 redetermination, we entered into the First Amendment to the Bank Credit Agreement (the "First Amendment") to restructure certain financial covenants in 2016, 2017 and 2018 in order to provide more flexibility in managing our balance sheet and managing the credit extended by our lenders if oil prices remain low over the next several years. The covenant changes included in the First Amendment were as follows:

- In 2016 and 2017, suspend the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant of 4.25 to 1.0 and replace it with a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 2.5 to 1.0 during the same time period. Currently, only debt under our Bank Credit Agreement would be considered consolidated senior secured debt for purposes of this ratio. If this covenant had been in place as of September 30, 2015, our ratio of senior secured debt to consolidated EBITDAX would have been 0.18 to 1.0 as of that date.
- Beginning in the first quarter of 2018, reinstate the ratio of consolidated total net debt to consolidated EBITDAX covenant utilizing an annualized EBITDAX amount for the first quarter of 2018 and building to a trailing four quarters by the end of 2018, with the maximum permitted ratios being 6.0 to 1.0 for the first quarter ended March 31, 2018, 5.5 to 1.0 for the second quarter ended June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ended September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ended March 31, 2019.
- In 2016 and 2017, institute a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 2.25 to 1.0. If this covenant had been in place as of September 30, 2015, our ratio of consolidated EBITDAX to consolidated interest charges would have been 6.03 to 1.0 as of that date.

The restructuring of covenants through the First Amendment was executed in consideration of a fee paid to the lenders. The First Amendment has no impact on the current ratio financial performance covenant, which will remain in place in 2015 and beyond. All of the above descriptions of financial covenants are qualified by the express language and defined terms contained in the Bank Credit Agreement.

Dividends. In all four quarters of 2014 and in each of the first three quarters of 2015, the Company's Board of Directors declared quarterly cash dividends of $0.0625 per common share. On September 21, 2015, in light of the continuing low oil price environment and its desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend, after payment of our third quarter dividend on September 29, 2015. By suspending the dividend, we will free up approximately $22 million of cash each quarter that was historically paid out in dividends, which can be directed to other uses. Dividends totaling $65.4 million and $65.2 million were paid to stockholders during the nine months ended September 30, 2015 and 2014, respectively.

Stock Repurchase Program. On September 21, 2015, the Company's Board of Directors reinstated the ability to repurchase shares under our share repurchase program, which authorization was suspended in November of 2014. During September and October of 2015, we repurchased 4.4 million shares of Denbury common stock for $11.8 million. We have spent a total of $951.8 million to repurchase 64.4 million shares of our common stock under this program between October 2011 and November 4, 2015 (approximately 16.0% of our outstanding shares at September 30, 2011), leaving us with $210.1 million available for future purchases. Our share repurchases are based on various parameters including, but not limited to, the price of our common stock, oil prices, free cash flow, our leverage or other funding sources available to us. There is no requirement that the remaining balance under the program be utilized, and there is no set expiration date for the repurchase program. We anticipate that any additional repurchases would be funded out of our excess cash flow and in a manner that would not increase bank borrowings beyond the year-end 2014 level. See Note 4, Stockholders' Equity, to the Unaudited Condensed Consolidated Financial Statements for further discussion.

Insurance Recoveries to Cover Costs of 2013 Delhi Field Release. Our remediation efforts related to the 2013 release of well fluids at the Denbury-operated Delhi Field were completed during the fourth quarter of 2013, and as of

September 30, 2015, virtually all of our total recorded cost of $130.8 million had been incurred.

We maintain insurance policies to cover certain costs, damages and claims related to releases of well fluids and remediation. We received a $25.0 million cost reimbursement in October 2014 related to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess liability insurance coverage, and an additional $4.5 million cost reimbursement in August 2015 from our insurance carrier providing well control coverage. We have not reached any agreement with our remaining carriers as to further reimbursements, but given our belief that under our policies we are entitled to reimbursement of between approximately one-third and two-thirds of our total costs, we have filed suit to pursue further reimbursements, the ultimate outcome of which cannot be predicted.

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, 2014, 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.

RESULTS OF OPERATIONS

Our tertiary operations represent a significant portion of our overall operations and are our primary long-term 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 – Financial Overview of Tertiary Operations in our Form 10-K for further information regarding these matters.

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

Operating Results Table

Certain of our operating results and statistics for the comparative three and nine months ended September 30, 2015 and 2014 are included in the following table:

In thousands, except per share and unit data	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating results				
Net income (loss) [1]	$(2,244,126)	$268,748	$(3,500,371)	$271,858
Net income (loss) per common share – basic [1]	(6.41)	0.77	(10.01)	0.78
Net income (loss) per common share – diluted [1]	(6.41)	0.77	(10.01)	0.77
Dividends declared per common share	0.0625	0.0625	0.1875	0.1875
Net cash provided by operating activities	272,676	340,392	699,397	885,097
Average daily production volumes				
Bbls/d	67,900	70,619	69,424	70,504
Mcf/d	21,066	19,147	22,357	22,671
BOE/d [2]	71,410	73,810	73,150	74,283
Operating revenues				
Oil sales	$285,742	$615,745	$939,744	$1,876,524
Natural gas sales	4,646	6,260	15,005	26,356
Total oil and natural gas sales	$290,388	$622,005	$954,749	$1,902,880
Commodity derivative contracts [3]				
Receipt (payment) on settlements of commodity derivatives	$160,677	$(24,914)	$433,293	$(102,255)
Noncash fair value adjustments on commodity derivatives [4]	(68,649)	277,179	(307,115)	103,080
Commodity derivatives income (expense)	$92,028	$252,265	$126,178	$825
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$45.74	$94.78	$49.58	$97.49
Natural gas price per Mcf	2.40	3.55	2.46	4.26
Unit prices – including impact of derivative settlements [3]				
Oil price per Bbl	$71.32	$90.92	$72.31	$92.22
Natural gas price per Mcf	2.87	3.61	2.89	4.13
Oil and natural gas operating expenses				
Lease operating expenses [5]	$113,902	$155,198	$387,156	$488,827
Marketing expenses, net of third-party purchases, and plant operating expenses	12,606	11,082	34,943	36,869
Production and ad valorem taxes	20,989	36,279	73,606	126,213
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$44.20	$91.60	$47.81	$93.83
Lease operating expenses [5]	17.34	22.86	19.39	24.10
Marketing expenses, net of third-party purchases, and plant operating expenses	1.91	1.63	1.75	1.82
Production and ad valorem taxes	3.19	5.34	3.69	6.22

CO_2 sources and helium – revenues and expenses				
CO_2 and helium sales and transportation fees	$9,144	$11,378	$23,268	$33,961
CO_2 and helium discovery and operating expenses	(1,017)	(11,434)	(2,909)	(22,229)
CO_2 and helium revenue and expenses, net	$8,127	$(56)	$20,359	$11,732

(1) Includes full cost pool ceiling test write-downs of $1.8 billion and $3.6 billion for the three and nine months ended September 30, 2015, respectively, and an impairment of goodwill charge of $1.3 billion for the three and nine months ended September 30, 2015.

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

(3) See also Commodity Derivative Contracts below and Item 3. Quantitative and Qualitative Disclosures about Market Risk for information concerning our derivative transactions.

(4) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure and is different from "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations in that the noncash fair value adjustments on commodity derivatives represents only the net change between periods of the fair market values of commodity derivative positions, and excludes the impact of settlements on commodity derivatives during the period, which were receipts on settlements of $160.7 million and $433.3 million for the three and nine months ended September 30, 2015, compared to payments on settlements of $24.9 million and $102.3 million for the three and nine months ended September 30, 2014. We believe that noncash fair value adjustments on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

(5) Lease operating expenses reported in this table include certain nonrecurring amounts, comprised of (1) lease operating expenses and related insurance recoveries recorded to remediate an area of Delhi Field (see Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release above), (2) a reimbursement for a retroactive utility rate adjustment, and (3) other insurance recoveries. If these amounts were excluded, lease operating expenses would have totaled $127.6 million and $400.9 million for the three and nine months ended September 30, 2015, respectively, and $165.1 million and $498.7 million for the three and nine months ended September 30, 2014, respectively, and lease operating expense per BOE would have averaged $19.43 and $20.08 for the three and nine months ended September 30, 2015, respectively, and $24.32 and $24.59 for the three and nine months ended September 30, 2014, respectively.

Production

Average daily production by area for each of the four quarters of 2014 and for the first, second, and third quarters of 2015 is shown below:

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2014	Second Quarter 2014	Third Quarter 2014	Fourth Quarter 2014	First Quarter 2015	Second Quarter 2015	Third Quarter 2015
Tertiary oil production							
Gulf Coast region							
Mature properties:							
Brookhaven	1,877	1,818	1,767	1,579	1,612	1,691	1,712
Eucutta	2,181	2,150	2,224	1,995	1,905	2,054	1,922
Mallalieu	1,837	1,839	1,869	1,653	1,574	1,537	1,427
Other mature properties (1)	6,283	6,156	6,189	5,864	5,710	5,888	5,885
Total mature properties	12,178	11,963	12,049	11,091	10,801	11,170	10,946
Delhi (2)	4,708	4,543	4,377	3,743	3,551	3,623	3,676
Hastings	4,618	4,759	4,917	4,811	4,694	5,350	5,114
Heidelberg	5,325	5,609	5,721	6,164	6,027	5,885	5,600
Oyster Bayou	4,055	4,415	4,605	5,638	5,861	5,936	5,962
Tinsley	8,430	8,518	8,310	8,767	8,928	8,740	7,311
Total Gulf Coast region	39,314	39,807	39,979	40,214	39,862	40,704	38,609
Rocky Mountain region							
Bell Creek	578	1,090	1,648	1,659	1,965	1,880	2,225
Total Rocky Mountain region	578	1,090	1,648	1,659	1,965	1,880	2,225
Total tertiary oil production	39,892	40,897	41,627	41,873	41,827	42,584	40,834
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	2,513	2,319	2,346	2,099	1,761	1,400	1,592
Texas	6,444	6,508	5,537	6,677	6,490	6,304	6,508
Other	1,031	1,049	1,083	1,082	1,006	906	846
Total Gulf Coast region	9,988	9,876	8,966	9,858	9,257	8,610	8,946
Rocky Mountain region							
Cedar Creek Anticline	19,007	19,155	18,623	18,553	18,522	18,089	17,515
Other	4,831	5,392	4,594	4,591	4,750	4,433	4,115
Total Rocky Mountain region	23,838	24,547	23,217	23,144	23,272	22,522	21,630
Total non-tertiary production	33,826	34,423	32,183	33,002	32,529	31,132	30,576
Total production	73,718	75,320	73,810	74,875	74,356	73,716	71,410

(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.

(2) Beginning with the fourth quarter of 2014, average daily Delhi Field production amounts reflect the reversionary assignment of approximately 25% of our interest in that field effective November 1, 2014. The effectiveness, timing, and scope of the reversionary assignment are subject to ongoing litigation, the ultimate outcome of which cannot be predicted.

Total Production

Total production during the third quarter of 2015 averaged 71,410 BOE/d, a decrease of 2,400 BOE/d (3%) compared to third quarter of 2014 production levels and a decrease of 2,306 BOE/d (3%) compared to second quarter of 2015 production levels. The change between the comparative third quarters was primarily a result of natural production declines at our mature tertiary properties in the Gulf Coast region and Cedar Creek Anticline ("CCA") in the Rocky Mountain region, as well as a temporary production decline at Tinsley Field and a contractual reversionary interest assignment at Delhi Field, each of which is discussed in further detail below. The production declines mentioned above and in other fields include what we currently estimate to be approximately 1,100 BOE/d of production (excluding Riley Ridge) that is shut-in attributable to wells that have become uneconomic to either produce or repair due to commodity prices at this time. These negative impacts to production were partially offset by increases in production at our newer tertiary floods. On a year-to-date basis, total production decreased 1,133 BOE/d (2%) between the first nine months of 2014 and 2015 as a result of the factors discussed above. Our production during the three and nine months ended September 30, 2015 was 95% oil, consistent with oil production of 96% and 95% during the three and nine months ended September 30, 2014.

Tertiary Production

Oil production from our tertiary operations during the third quarter of 2015 decreased 793 Bbls/d (2%) compared to tertiary oil production levels in the same period in 2014, and decreased 1,750 Bbls/d (4%) when comparing tertiary oil production between the second and third quarters of 2015. The year-over-year decrease was largely due to Tinsley Field facility processing constraints and impacts of warmer temperatures restricting CO_2 injection and recycling, which caused us to temporarily shut-in certain wells at Tinsley Field. We expect production at Tinsley Field to return to higher levels in the fourth quarter of 2015; however, production has likely peaked and will be on a gradual decline going forward. The year-over-year decrease was further impacted by natural production declines at our mature properties in the Gulf Coast region, as well as our ownership interest at Delhi Field decreasing as of November 1, 2014, due to a contractual reversionary assignment of approximately 25% of our interest to the seller of the field, the effectiveness, timing, and scope of which are subject to ongoing litigation, and which reduced our third quarter 2015 production by approximately 1,200 Bbls/d. Partially offsetting the year-over-year decrease was an increase in production from continued field development and expansion of facilities in our tertiary floods at Oyster Bayou Field in our Gulf Coast region and Bell Creek Field in our Rocky Mountain region. The sequential-quarter decrease in production was primarily due to the Tinsley Field items noted above, partially offset by a production increase at Bell Creek Field.

Non-Tertiary Production

Production from our non-tertiary operations averaged 30,576 BOE/d during the third quarter of 2015, a decrease of 1,607 BOE/d (5%) compared to the third quarter of 2014 levels and a decrease of 556 BOE/d (2%) when compared to the second quarter of 2015 levels. These decreases are primarily comprised of natural production declines at CCA and our other non-tertiary Rocky Mountain properties, as well as shutting in certain wells that are uneconomic to either produce or repair at this time due to commodity prices. The year-over-year decrease was partially offset by increases in production at Conroe Field and production associated with our Manvel Field acquisition which was completed during the second quarter of 2015, both of which are included in our Texas non-tertiary properties. Natural gas production from Riley Ridge was negligible during both the third quarter of 2014 and 2015 due to continued downtime as a result of, among other things, design, equipment, machinery and mechanical well failures. We currently expect that natural gas production at Riley Ridge will continue to be shut-in for some time as we develop and evaluate solutions to eliminate sulfur build-up in those wells. Production from our other non-tertiary properties is generally on decline, and in some instances the decline is pronounced when non-tertiary wells are shut-in as part of an initiation or expansion of our tertiary floods in a field or an area of a field.

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

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and nine months ended September 30, 2015 decreased 53% and 50%, respectively, compared to these revenues for the same periods in 2014, and decreased 21% sequentially when compared to oil and natural gas revenues in the three months ended June 30, 2015. The changes in our oil and natural gas revenues during the comparative three and nine month periods are due to changes in production quantities and commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

In thousands	Three Months Ended September 30, 2015 vs. 2014 Decrease in Revenues	Three Months Ended September 30, 2015 vs. 2014 Percentage Decrease in Revenues	Nine Months Ended September 30, 2015 vs. 2014 Decrease in Revenues	Nine Months Ended September 30, 2015 vs. 2014 Percentage Decrease in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$(20,219)	(3)%	$(29,020)	(2)%
Decrease in commodity prices	(311,398)	(50)%	(919,111)	(48)%
Total decrease in oil and natural gas revenues	$(331,617)	(53)%	$(948,131)	(50)%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first quarters, second quarters, third quarters, and nine months ended September 30, 2015 and 2014:

	Three Months Ended March 31, 2015	2014	Three Months Ended June 30, 2015	2014	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Average net realized prices:								
Oil price per Bbl	$46.02	$97.69	$56.92	$100.04	$45.74	$94.78	$49.58	$97.49
Natural gas price per Mcf	2.54	4.71	2.44	4.39	2.40	3.55	2.46	4.26
Price per BOE	44.45	94.03	54.69	95.86	44.20	91.60	47.81	93.83
Average NYMEX differentials:								
Oil per Bbl	$(2.81)	$(0.91)	$(0.89)	$(3.03)	$(0.96)	$(2.53)	$(1.52)	$(2.16)
Natural gas per Mcf	(0.28)	(0.02)	(0.30)	(0.19)	(0.34)	(0.40)	(0.30)	(0.16)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, decreased 52% during the third quarter of 2015 from the average price received during the third quarter of 2014. Company-wide average oil price differentials in the third quarter of 2015 were $0.96 per Bbl below NYMEX, compared to an average differential of $2.53 per Bbl below NYMEX in the third quarter of 2014, principally due to improvement in our Rocky Mountain region price differentials. 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, crude oil quality, and location differentials. The oil differentials we received in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

Our average NYMEX oil differential in the Gulf Coast region was a positive $0.92 per Bbl and $2.15 per Bbl during the three months ended September 30, 2015 and 2014, respectively, and a positive $1.86 per Bbl during the three months ended June 30, 2015. These differentials are impacted significantly by the changes in prices received for our crude oil sold under LLS index prices relative to the change in NYMEX prices, as well as various other price adjustments such as those noted above. The quarterly average LLS-to-NYMEX differential (on a trade-month basis) was a positive $3.89 per Bbl in the third quarter of 2015, up from a positive $3.41 per Bbl in the third quarter of 2014 and down from a positive $6.29 per Bbl in the second quarter of 2015. During the third quarter of 2015, we sold approximately 44% of our crude oil at prices based on the LLS index price, approximately 15%

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 percentage of crude oil sold at prices partially tied to the LLS index price decreased from the third quarter of 2014 due to a contract expiration at the end of June 2015, while the percentage of crude oil sold at prices based on the LLS index was relatively consistent with that realized during the third quarter of 2014.

NYMEX oil differentials in the Rocky Mountain region averaged $4.73 per Bbl and $11.96 per Bbl below NYMEX during the three months ended September 30, 2015 and 2014, respectively, and $6.48 per Bbl below NYMEX during the three months ended June 30, 2015. Differentials in the Rocky Mountain region can fluctuate significantly on a month-to-month basis due to weather, refinery or transportation issues, and Canadian and U.S. crude oil price index volatility.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be quite large, the absolute impact of these changes on our results has historically been minor, as natural gas sales represented only approximately 2% of our oil and natural gas revenues during the nine months ended September 30, 2015.

Commodity 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, 2015 and 2014:

	Three Months Ended September 30,					
	2015	2014	2015	2014	2015	2014
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Receipt (payment) on settlements of commodity derivatives	$159,770	$(25,016)	$907	$102	$160,677	$(24,914)
Noncash fair value adjustments on commodity derivatives [1]	(68,054)	276,240	(595)	939	(68,649)	277,179
Total income	$91,716	$251,224	$312	$1,041	$92,028	$252,265

	Nine Months Ended September 30,					
	2015	2014	2015	2014	2015	2014
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Receipt (payment) on settlements of commodity derivatives	$430,669	$(101,470)	$2,624	$(785)	$433,293	$(102,255)
Noncash fair value adjustments on commodity derivatives [1]	(305,198)	102,521	(1,917)	559	(307,115)	103,080
Total income (expense)	$125,471	$1,051	$707	$(226)	$126,178	$825

(1) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure. See Operating Results Table above for a discussion of the reconciliation between noncash fair value adjustments on commodity derivatives to

"Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

For the fourth quarter of 2015, we have commodity derivative contracts consisting of a combination of enhanced swaps and three-way collars covering a total of 38,000 Bbls/d. Roughly half of these derivative contracts are three-way collars, so the variability in potential cash flows from these types of hedges exposes us to more downside price risk than our enhanced swaps. These 2015 three-way collars, which include both NYMEX and LLS hedges, have a weighted average floor of approximately $86 per Bbl ($85 per Bbl and $88 per Bbl for NYMEX and LLS hedges, respectively) and a weighted average ceiling price of approximately $100 per Bbl ($99 per Bbl and $101 per Bbl for NYMEX and LLS hedges, respectively). Our three-way collars and enhanced swaps all include sold puts that have a weighted average price of $68 per Bbl, limiting the benefit that our hedges provide us to the extent that oil prices remain below the price of these sold puts.

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 changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations. The details of our outstanding commodity derivative contracts at September 30, 2015, are included in Note 5, Commodity Derivative Contracts, to the Unaudited Condensed Consolidated Financial Statements. Also, see Item 3, Quantitative and Qualitative Disclosures about Market Risk below for additional discussion on our commodity derivative contracts.

Production Expenses

Lease Operating Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data	2015	2014	2015	2014
Lease operating expense				
Tertiary	$73,749	$95,671	$238,707	$292,238
Non-tertiary	53,868	69,433	162,164	206,495
Total recurring lease operating expense	127,617	165,104	400,871	498,733
Tertiary – nonrecurring amounts	(13,715)	(9,906)	(13,715)	(9,906)
Total lease operating expense	$113,902	$155,198	$387,156	$488,827
Lease operating expense per BOE				
Tertiary	$19.63	$24.98	$20.94	$26.23
Non-tertiary	19.15	23.45	18.91	22.60
Total recurring lease operating expense per BOE	19.43	24.32	20.08	24.59
Tertiary – nonrecurring amounts	(3.65)	(2.58)	(1.20)	(0.89)
Total lease operating expense per BOE	17.34	22.86	19.39	24.10

Our lease operating costs have declined as a result of our cost reduction efforts throughout 2014 and 2015, as well as general market decreases in the prices of many of the components of these costs, and our total recurring normalized lease operating expenses in the third quarter of 2015 were less than $19.50 per BOE. Our total lease operating expense in the third quarter of 2015 was $17.34 per BOE, as during the third quarter we recognized insurance and other reimbursements totaling $13.7 million, comprised of a reimbursement for a retroactive utility rate adjustment ($9.6 million) and an insurance reimbursement for previous well control costs ($4.1 million). During the third quarter of 2014, we recognized certain lease operating expenses and related insurance recoveries to remediate an area of Delhi Field, for a net reimbursement of $9.9 million (see Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release above). Our recurring lease operating expenses per BOE decreased in each of our last seven sequential quarters and decreased a total of 26% between the fourth quarter of 2013 and the third quarter of 2015. Total lease operating expenses, excluding nonrecurring amounts, decreased $37.5 million (23%) and $97.9 million (20%) on an absolute-dollar basis or $4.89 (20%) and $4.51 (18%) on a per-BOE basis during the three and nine months ended September 30, 2015, compared to levels in the same periods in 2014. The decrease during both periods was due to cost decreases in most categories of lease operating expenses, the most significant of which included (1) a decrease in workover costs, (2) lower power costs due to lower rates and usage, (3) lower CO_2 expense resulting from a decrease in CO_2 injection volumes and a decrease in the cost of CO_2, which correlates with oil prices, and (4) lower third-party contractor and vendor expenses such as contract labor and chemical costs. Sequentially, excluding insurance and other reimbursements, lease operating expenses declined 3% on an absolute-dollar basis and 1% on a per-BOE basis between the second and third quarters of 2015, as we have seen many of our costs decline, with the decrease in CO_2 and workover expense the primary components of lease operating expense cost reductions.

Excluding nonrecurring amounts detailed above, tertiary lease operating expenses decreased $21.9 million and $53.5 million on an absolute-dollar basis and decreased $5.35 and $5.29 on a per-barrel basis during the three and nine months ended September 30, 2015, respectively, compared to the levels in the same periods in 2014. The decreases in both periods were primarily due to the same reasons detailed in the paragraph above. As part of our innovation and improvement initiative, we have identified fields where we have been able to reduce CO_2 injections without impacting oil production. As such, we have been able to reduce injected CO_2 volumes in the Gulf Coast region by 21% when compared to those in the prior year third quarter and by 11% on a sequential-quarter basis. In addition, our operating costs on a per-barrel basis at our newer tertiary floods such as Oyster Bayou and Bell Creek fields have improved from those in the third quarter of 2014 due to production increases. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially, as we experienced in 2013 and 2014 with our Bell Creek flood, and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when operating expenses per barrel will again increase. When comparing the third quarter of 2015 to the second quarter of 2015, tertiary lease operating expenses, excluding insurance and other reimbursements, decreased $5.8 million (7%) or $0.89 (4%) on a per-barrel basis.

Currently, our CO_2 expense comprises approximately 20% of our typical tertiary lease operating expenses, and for the CO_2 reserves we already own, consists of 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 industrial sources. During the third quarters of 2015 and 2014, approximately 57% and 64%, respectively, of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us. 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 during the third quarter of 2015 was approximately $0.31 per Mcf, including taxes paid on CO_2 production but excluding depletion and depreciation of capital. This rate during the third quarter of 2015 was lower than the $0.40 per Mcf during the third quarter of 2014, primarily driven by reductions in the price of CO_2 due to the significant decline in oil prices, and was lower than the $0.33 per Mcf comparable measure during the second quarter of 2015 due to commodity prices decreasing during the third quarter of 2015 and the impact of lower CO_2 utilization from Jackson Dome. Including the cost of depreciation and amortization of capital expended at our CO_2 source fields and industrial sources, but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was $0.42 per Mcf and $0.51 per Mcf during the third quarters of 2015 and 2014, respectively.

Non-tertiary lease operating expenses decreased 22% on an absolute-dollar basis and 18% on a per-BOE basis between the three months ended September 30, 2015 and 2014. Non-tertiary lease operating expenses decreased 21% on an absolute-dollar basis and 16% on a per-BOE basis between the nine months ended September 30, 2015 and 2014. The decreases in both periods were primarily due to lower workover costs, repairs and maintenance costs, and lower third-party contractor and vendor expenses such as contract labor and chemical costs during the 2015 periods. On a sequential-quarter basis, our non-tertiary lease operating expenses increased $1.2 million (2%) on an absolute-dollar basis and increased $0.56 (3%) on a per-BOE basis during the third quarter of 2015.

Marketing and Plant Operating Expenses

Marketing and plant operating expenses primarily consist of amounts incurred relating to the marketing, processing, and transportation of oil and natural gas production, as well as expenses related to our Riley Ridge gas processing facility. Marketing and plant operating expenses decreased $0.9 million (6%) and $9.9 million (20%) during the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014, primarily due to reductions in marketing, compression, and plant processing fees, as well as reductions related to the Riley Ridge gas processing facility, which is currently shut-in.

Taxes Other Than Income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income decreased $14.4 million and $50.9 million during the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014. The levels of taxes other than income during most periods are generally aligned with fluctuations in oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and employees	2015	2014	2015	2014
Gross cash compensation and administrative costs	$77,879	$87,355	$257,524	$265,400
Gross stock-based compensation	9,621	10,986	29,364	33,343
Operator labor and overhead recovery charges	(39,075)	(42,763)	(122,630)	(128,836)
Capitalized exploration and development costs	(15,518)	(15,212)	(47,124)	(46,896)
Net G&A expense	$32,907	$40,366	$117,134	$123,011
G&A per BOE:				
Net administrative costs	$3.93	$4.72	$4.84	$4.88
Net stock-based compensation	1.08	1.22	1.03	1.19
Net G&A expense	$5.01	$5.94	$5.87	$6.07
Employees as of September 30	1,354	1,502		

Gross cash compensation and administrative costs on an absolute-dollar basis decreased $9.5 million (11%) and $7.9 million (3%) during the three and nine months ended September 30, 2015, respectively, compared to those costs in the same periods in 2014. As part of our efforts to reduce overhead and operating costs in response to the significant decline in oil prices, we reduced our employee headcount in mid-2015 through an involuntary workforce reduction, which contributed to an overall headcount reduction of approximately 11% between January 1, 2015 and September 30, 2015. The severance payments associated with the workforce reduction were not material to the quarterly financial results. The decrease in gross cash compensation and administrative costs during the three and nine months ended September 30, 2015, compared to the same periods in 2014, was primarily due to lower employee-related costs such as salaries, bonus accruals and long-term incentives resulting from reductions in employee headcount during 2015 and a reduction in costs associated with our stock purchase plan following its termination at the end of the first quarter of 2015, partially offset by severance payments associated with the workforce reduction and higher employee-related insurance costs.

Net G&A expense on a per-BOE basis decreased 16% and 3% during the three and nine months ended September 30, 2015, respectively, compared to levels in the same periods in 2014. The changes between the comparative three and nine month periods were primarily based on the changes noted in gross cash compensation and administrative costs and lower gross stock-based compensation associated with the reduction in headcount, partially offset by lower operator labor and overhead recovery charges.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. 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.

Interest and Financing Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and interest rates	2015	2014	2015	2014
Cash interest expense	$44,996	$47,158	$137,605	$147,115
Noncash interest expense	2,310	3,456	6,810	10,434
Less: capitalized interest	(8,081)	(5,862)	(25,228)	(17,413)
Interest expense, net	$39,225	$44,752	$119,187	$140,136
Interest expense, net per BOE	$5.97	$6.59	$5.97	$6.91
Average debt outstanding	$3,426,636	$3,622,579	$3,541,263	$3,618,149
Average interest rate (1)	5.3 %	5.2 %	5.2 %	5.4 %

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

As reflected in the table above, cash interest expense during the three and nine months ended September 30, 2015, decreased when compared to the same periods in 2014 as a result of the reduction in our average debt outstanding. The slight decrease in our average interest rate during the nine months ended September 30, 2015, compared to the same period in 2014, was due to our April 2014 long-term debt refinancing, whereby we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 to replace our $996.3 million of 8¼% Senior Subordinated Notes due 2020. Capitalized interest during the three and nine months ended September 30, 2015, increased $2.2 million (38%) and $7.8 million (45%), respectively, compared to the same periods in 2014, primarily due to incremental capitalized interest on projects that qualify for interest capitalization.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data	2015	2014	2015	2014
Depletion and depreciation of oil and natural gas properties	$90,390	$114,224	$322,440	$337,841
Depletion and depreciation of CO_2 properties	5,945	7,041	20,703	22,341
Amortization of asset retirement obligations	2,441	2,207	7,154	6,605
Depreciation of pipelines, plants and other property and equipment	22,630	23,088	69,007	69,067
Total DD&A	$121,406	$146,560	$419,304	$435,854
DD&A per BOE:				
Oil and natural gas properties	$14.13	$17.15	$16.51	$16.99
CO_2, pipelines, plants and other property and equipment	4.35	4.43	4.49	4.50
Total DD&A cost per BOE	$18.48	$21.58	$21.00	$21.49
Write-down of oil and natural gas properties	$1,760,600	$—	$3,612,600	$—

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. DD&A of oil and natural gas properties and asset retirement obligations on an absolute-dollar basis decreased 20% and 4% during the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014. On a per-BOE basis, DD&A of oil and natural gas properties and asset retirement obligations decreased 18% and 3% during the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014. These decreases were primarily due to a reduction in depletable costs associated with our reserves base resulting from the full cost pool ceiling test write-downs recognized during the first half of 2015. Given the additional full cost pool ceiling test write-down recognized during the three months ended September 30, 2015, we currently expect our DD&A rate in the fourth quarter of 2015 to further decrease from the third quarter of 2015 rate by approximately $3 to $4 per BOE. However, the overall decrease in our fourth quarter DD&A rate will also be impacted by potential changes in reserve volumes, production, and future capital expenditure estimates, among other factors, and therefore, the actual decrease will most likely differ from this estimate.

Depletion and depreciation of our CO_2 properties, pipelines, plants and other property and equipment decreased 5% on an absolute-dollar basis and 2% on a per-BOE basis during the three months ended September 30, 2015, compared to the same period in 2014, primarily due to a decrease in CO_2 production during the period, as we have been able to reduce the level of CO_2 production and injections with only a slight impact to our oil production.

Write-Down of Oil and Natural Gas Properties

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. As a result of the precipitous and continuing decline in NYMEX oil prices since the fourth quarter of 2014, the rolling first-day-of-the-month average oil price for the preceding 12 months, after adjustments for market differentials by field, has fallen throughout 2015, from $79.55 per Bbl for the first quarter of 2015, to $68.48 per Bbl for the second quarter of 2015, and $56.74 per Bbl for the third quarter of 2015. In addition, the first-day-of-the-month average natural gas price for the preceding 12 months, after adjustments for market differentials by field, was $3.95 per Mcf for the first quarter of 2015, $3.74 per Mcf for the second quarter of 2015, and $3.64 per Mcf for the third quarter of 2015. The prices used for the third quarter of 2015 represent a decrease of 38% for crude oil and 15% for natural gas prices compared to adjusted prices used to calculate the December 31, 2014, full cost ceiling value. These falling prices have led to our recognizing full cost pool ceiling test write-downs of $1.8 billion, $1.7 billion and $0.2 billion during the three months ended September 30, 2015, June 30, 2015, and March 31, 2015, respectively. We currently expect that we will record an additional write-down in the fourth quarter of 2015 in a range of similar magnitude to the write-down recorded in the third quarter of 2015 if oil and natural gas prices remain at or near late-October 2015 levels for the remainder of 2015, as the 12-month average prices used in determining the full cost ceiling value would reflect lower prices in the fourth quarter of 2015 than in the last quarter of 2014. Any such write-down would also be affected, in part, by changes in proved oil and natural gas reserve volumes, future capital expenditures and operating costs.

Impairment of Goodwill

We are required to test goodwill for impairment on an interim basis when we determine that it is more likely than not that the fair value of our reporting unit is less than its carrying amount. Our enterprise value (combined market capitalization plus a control premium of 10% and the fair value of our long-term debt) declined by approximately $2.5 billion between June 30 and September 30, 2015; therefore, we concluded that a goodwill impairment test was required to be performed in the third quarter.

For the goodwill impairment test, we compared the fair value of the reporting unit (enterprise value) to the fair value of its assets and liabilities. Oil and natural gas reserves, which represent the most significant assets requiring valuation, were estimated using the expected present value of future net cash flows method based on September 30, 2015, NYMEX oil and natural gas futures prices for the next five years, which ranged from approximately $47 per Bbl to $58 per Bbl for oil and approximately $3 per MMBtu for natural gas, adjusted for current price differentials. In addition to future oil and natural gas pricing, the most significant assumptions impacting the projections of future net cash flows include projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, risk adjustment factors applied to probable and possible oil and natural gas reserve cash flows, projected recovery factors of oil and natural gas reserves, and a weighted average cost of capital discount rate of 9% per annum applied to all net cash flows. Because the fair value of the reporting unit (enterprise value) did not exceed the fair value of assets and liabilities, we recorded a goodwill impairment charge of $1.3

billion during the three months ended September 30, 2015, to fully impair the carrying value of our goodwill. Approximately $1.0 billion of the $1.3 billion goodwill balance was associated with the March-2010 merger with Encore Acquisition Company. The fair value of our reporting unit (enterprise value) declining at a rate greater than the decline in NYMEX oil futures prices and resulting value of our oil and natural gas reserves between June 30 and September 30, 2015, was a primary cause of the impairment.

Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Impairment Assessment of Goodwill in the Form 10-K for a complete discussion of the goodwill impairment test, including a discussion of relevant inputs.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE amounts and tax rates	2015	2014	2015	2014
Current income tax expense	$1,184	$214	$1,063	$532
Deferred income tax expense (benefit)	(732,064)	167,356	(1,432,572)	168,967
Total income tax expense (benefit)	$(730,880)	$167,570	$(1,431,509)	$169,499
Average income tax expense (benefit) per BOE	$(111.25)	$24.68	$(71.68)	$8.36
Effective tax rate	24.6%	38.4%	29.0%	38.4%

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. As of September 30, 2015, we had $37.0 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of a new tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized a tax valuation allowance in the second quarter of 2015 of $30.5 million to reduce the carrying value of our deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

Our income taxes are based on estimated statutory rates of approximately 38% in 2015 and 2014. Our effective tax rate for the three months ended September 30, 2015, was lower than our estimated statutory rate, as a significant portion of the book value of our goodwill impaired during the quarter had no related tax basis. Therefore, no corresponding deferred tax benefit was recognized related to that portion of the goodwill impairment. Our effective tax rate for the nine months ended September 30, 2015, was further impacted by the tax valuation allowance discussed above, which also reduced the net deferred tax benefit recognized. Our effective tax rate for the three and nine months ended September 30, 2014, was slightly above our estimated statutory rate, primarily due to a reduction in the domestic production activities deduction and the inclusion of differences between our 2013 tax provision and our 2013 filed tax returns. The amounts recorded as current income tax expense represent our federal taxes, reduced by enhanced oil recovery credits during the two periods, plus our state income taxes. The deferred income tax benefits during the three and nine months ended September 30, 2015, were primarily due to the impact of the write-down of our oil and natural gas properties during the year.

As of September 30, 2015, we had an estimated $48.5 million of enhanced oil recovery credits to carry forward related to our tertiary operations and $39.2 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2015 or future years. These enhanced oil recovery credits do not begin to expire until

2023. We currently do not expect to earn additional enhanced oil recovery credits during 2015.

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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 significant individual components is discussed above.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Per-BOE data	2015	2014	2015	2014
Oil and natural gas revenues	$44.20	$91.60	$47.81	$93.83
Receipt (payment) on settlements of commodity derivatives	24.46	(3.67)	21.70	(5.04)
Lease operating expenses – excluding nonrecurring amounts	(19.43)	(24.32)	(20.08)	(24.59)
Lease operating expenses – nonrecurring amounts	2.09	1.46	0.69	0.49
Production and ad valorem taxes	(3.19)	(5.34)	(3.69)	(6.22)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.91)	(1.63)	(1.75)	(1.82)
Production netback	46.22	58.10	44.68	56.65
CO_2 and helium sales, net of operating and exploration expenses	1.24	—	1.02	0.57
General and administrative expenses	(5.01)	(5.94)	(5.87)	(6.07)
Interest expense, net	(5.97)	(6.59)	(5.97)	(6.91)
Other	0.43	1.00	0.67	1.08
Changes in assets and liabilities relating to operations	4.59	3.56	0.49	(1.67)
Cash flows from operations	41.50	50.13	35.02	43.65
DD&A	(18.48)	(21.58)	(21.00)	(21.49)
Write-down of oil and natural gas properties	(267.99)	—	(180.90)	—
Impairment of goodwill	(192.02)	—	(63.17)	—
Deferred income taxes	111.43	(24.65)	71.74	(8.33)
Loss on early extinguishment of debt	—	—	—	(5.62)
Noncash fair value adjustments on commodity derivatives	(10.45)	40.82	(15.38)	5.08
Other noncash items	(5.57)	(5.14)	(1.59)	0.12
Net income (loss)	$(341.58)	$39.58	$(175.28)	$13.41

CRITICAL ACCOUNTING POLICIES

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

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, timing of CO_2 injections and initial production responses thereto, anticipated future cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and their availability, helium reserves, potential reserves, percentages of recoverable original oil in place, hydrocarbon prices, pricing or cost assumptions based on current and projected future oil and gas prices, cost and availability of equipment and services, liquidity, availability of capital, borrowing capacity, regulatory matters, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, mark-to-market values, possible future write-downs of oil and natural gas reserves, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, estimates of the range of potential insurance recoveries, 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," "projected," "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 prices and consequently in the prices received or demand for the Company's oil and natural gas; decisions as to production levels and/or pricing by OPEC in future periods; 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.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

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. As of September 30, 2015, we had $210.0 million in outstanding borrowings on our bank credit facility. 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. 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.

The following table presents the principal balances of our debt, by maturity date, as of September 30, 2015:

In thousands	2017	2019	2021	2022	2023	Total
Variable rate debt:						
Bank Credit Facility (weighted average interest rate of 1.8% at September 30, 2015)	$—	$210,000	$—	$—	$—	$210,000
Fixed rate debt:						
6 % Senior Subordinated Notes due 2021	—	—	400,000	—	—	400,000
5½% Senior Subordinated Notes due 2022	—	—	—	1,250,000	—	1,250,000
4 % Senior Subordinated Notes due 2023	—	—	—	—	1,200,000	1,200,000
Other Subordinated Notes	2,250	—	—	—	—	2,250

See Note 2, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements for details regarding our long-term debt.

Oil and Natural Gas Derivative Contracts

Historically, we have entered 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 and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. 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 have entered into a combination of enhanced swaps and three-way collars covering a total of 38,000 Bbls/d for the fourth quarter of 2015. Roughly half of these derivative contracts are three-way collars, so the variability in potential cash flows from these types of hedges exposes us to more downside price risk than our enhanced swaps. In addition, the sold puts that are part of our three-way collars and enhanced swaps limit the benefit our hedges provide us to the extent oil prices remain below the price of our sold puts. We anticipate that we may use more fixed-price swaps in the future or a combination of fixed-price swaps and collars as we look to provide more certainty around our cash flows in order to execute on our capital development plans and retain a healthy balance sheet. 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 (or affiliates of such lenders). 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 treatment 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, 2015, our commodity derivative contracts were recorded at their fair value, which was a net asset of $199.4 million, a $68.7 million decrease from the $268.1 million net asset recorded at June 30, 2015, and a $307.1 million decrease from the $506.5 million net asset recorded at December 31, 2014. Changes in this value are comprised of the expiration of commodity derivative contracts during 2015, new commodity derivative contracts entered into during 2015 for future periods, and to the changes in oil and natural gas futures prices between December 31, 2014 and September 30, 2015.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices and natural gas futures prices as of September 30, 2015, and assuming both a 10% increase and decrease thereon, we would expect to receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

	Receipt / (Payment)	
In thousands	Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
Futures prices as of September 30, 2015	$198,483	$1,030
10% increase in prices	185,102	902
10% decrease in prices	211,864	1,159

Our commodity derivative contracts are used as an economic hedge of our exposure to commodity price risk associated with anticipated future production. As a result, changes in receipts or payments of our commodity derivative contracts due to changes in commodity prices as reflected in the above table would be mostly offset by a corresponding increase or decrease in the cash receipts on sales of our oil or natural gas production to which those commodity derivative contracts relate.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our 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 management, including our Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2015, to ensure that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and our 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 2015, 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

We are involved in various lawsuits, claims and 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 business or finances, litigation is subject to inherent uncertainties. Although a single or multiple adverse rulings or settlements could possibly have a material adverse effect on our business or finances, we only accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

In mid-2006, Denbury Onshore, LLC ("Denbury Onshore") purchased its original interest in the Delhi Field in northeastern Louisiana from NGS Sub Corp, ("NGS"), a subsidiary of Evolution Petroleum Corporation (together with its subsidiaries, "Evolution"). Under the purchase documents, Denbury Onshore committed to develop the enhanced production of a specific portion of Delhi Field, the Holt Bryant Unit, and after Denbury Onshore's receipt of a defined level of net cash flow from the Unit (as defined in the agreements, "payout"), to assign reversionary interests in the Unit back to NGS. After several years of dispute regarding payout calculations and related contractual terms, in December 2013, Evolution filed suit against Denbury Onshore in the 133rd Judicial District Court in Houston, Harris County, Texas for unspecified damages, alleging breach of contract, and requesting declaratory judgment as to various provisions of the purchase documents and accompanying oil and gas conveyancing instruments, including as to the method of calculation and timing of payout, the sharing of various costs, and the timing and extent of post-payout assignments from Denbury Onshore to NGS. In February 2014, we filed an answer and counterclaim denying Evolution's claims and alleging breach of contract by Evolution for failing to convey the full interest for which we paid and violating our preferential purchase rights, and asking for declaratory judgment as to purchase document terms, including those pertaining to the determination of payout, the assignment provisions of the documents, and cost sharing.

In March 2015, Evolution filed its First Amended Petition (subsequently further amended in June 2015), adding allegations of negligence and gross negligence against Denbury Onshore in connection with the June 2013 Delhi Field release of well fluids, the remediation of which was completed in the fourth quarter of 2013 (see Note 7, Commitments and Contingencies, to our Unaudited Condensed Consolidated Financial Statements). Evolution claims for the first time in the First Amended Petition, that it estimates its damages attributable to its allegations in the case exceed $200 million. The First Amended Petition also adds a claim for unspecified punitive damages. There has only been limited discovery in the case to date, and Evolution has not specified the basis for the amount of its claimed damages estimate. The case is currently set for trial in April 2016. We believe that Evolution's claims with respect to this matter are without merit and intend to vigorously defend against them and pursue our rights under the purchase documents.

Item 1A. Risk Factors

Information with respect to the Company's 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 contained in the Form 10-K since its filing.

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 2015:

Month	Total Number of Shares Purchased (1)	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) (2)
July 2015	9,489	$5.15	—	$221.9
August 2015	2,229	3.72	—	221.9
September 2015	2,693,702	2.58	2,690,011	214.9
Total	2,705,420		2,690,011	

(1) Stock repurchases during the third quarter of 2015 other than those under our common stock 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.

(2) In October 2011, the Company's Board of Directors approved a common share repurchase program for up to $500 million of Denbury's common stock. During 2012 and 2013, the Board of Directors increased the dollar amount of Denbury common shares that could be purchased under the program to an aggregate of up to $1.162 billion. On September 21, 2015, the Company’s Board of Directors reinstated the ability to repurchase shares under our share repurchase program, which authorization was suspended in November of 2014. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

Between early October 2011, when we announced the commencement of a common share repurchase program, and November 4, 2015, we repurchased 64.4 million shares of Denbury common stock (approximately 16.0% of our outstanding shares of common stock at September 30, 2011) for $951.8 million, with an additional $210.1 million remaining authorized for purchases of common stock under this repurchase program.

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.	Exhibit
10(a)*	Officer Resignation Agreement and General Release, effective as of September 21, 2015, by and between Denbury Resources Inc. and Bradford M. Kerr.
10(b)	Standalone Restricted Share New Hire Inducement Award Agreement, dated September 8, 2015, by and between Denbury Resources Inc. and Christian S. Kendall (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 8, 2015, File No. 001-12935).
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

*Included herewith.

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SIGNATURES

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

	DENBURY RESOURCES INC.
November 6, 2015	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
November 6, 2015	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

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