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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2016
OR

☐ **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 ☑ No ☐

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 ☑ No ☐

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 ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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, 2016
Common Stock, $.001 par value	398,405,338

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, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$ 3,273	$ 2,812
Accrued production receivable	102,880	100,413
Trade and other receivables, net	45,019	87,093
Derivative assets	307	142,846
Other current assets	11,238	10,005
Total current assets	162,717	343,169
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	10,333,768	10,245,195
Unevaluated properties	929,056	894,948
CO_2 properties	1,186,572	1,187,458
Pipelines and plants	2,287,622	2,293,219
Other property and equipment	393,616	408,194
Less accumulated depletion, depreciation, amortization and impairment	(10,641,296)	(9,653,205)
Net property and equipment	4,489,338	5,375,809
Other assets	164,746	166,555
Total assets	$ 4,816,801	$ 5,885,533
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 173,770	$ 253,197
Oil and gas production payable	74,046	87,337
Derivative liabilities	74,229	—
Current maturities of long-term debt (including future interest payable of $50,974 and $0, respectively – see Note 2)	83,200	32,481
Total current liabilities	405,245	373,015
Long-term liabilities		
Long-term debt, net of current portion (including future interest payable of $203,686 and $0, respectively – see Note 2)	2,903,051	3,245,114
Asset retirement obligations	132,950	138,919
Deferred tax liabilities, net	505,689	852,089
Other liabilities	22,522	27,484
Total long-term liabilities	3,564,212	4,263,606
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; 401,996,605 and 354,541,626 shares issued, respectively	402	355
Paid-in capital in excess of par	2,527,787	2,353,549
Accumulated deficit	(1,633,264)	(1,058,954)
Treasury stock, at cost, 3,889,297 and 3,124,311 shares, respectively	(47,581)	(46,038)
Total stockholders' equity	847,344	1,248,912
Total liabilities and stockholders' equity	$ 4,816,801	$ 5,885,533

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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,	
	2016	2015	2016	2015
Revenues and other income				
Oil, natural gas, and related product sales	$ 239,930	$ 290,388	$ 674,401	$ 954,749
CO_2 sales and transportation fees	6,253	9,144	19,147	23,268
Interest income and other income	7,802	4,068	10,429	9,926
Total revenues and other income	253,985	303,600	703,977	987,943
Expenses				
Lease operating expenses	106,522	113,902	308,988	387,156
Marketing and plant operating expenses	14,452	14,458	40,645	40,358
CO_2 discovery and operating expenses	861	1,017	2,539	2,909
Taxes other than income	20,401	25,607	59,997	85,841
General and administrative expenses	24,643	32,907	81,089	117,134
Interest, net of amounts capitalized of $6,875, $8,081, $18,944, and $25,228, respectively	24,778	39,225	103,007	119,187
Depletion, depreciation, and amortization	55,012	121,406	198,919	419,304
Commodity derivatives expense (income)	(21,224)	(92,028)	99,811	(126,178)
Gain on debt extinguishment	(7,826)	—	(115,095)	—
Write-down of oil and natural gas properties	75,521	1,760,600	810,921	3,612,600
Impairment of goodwill	—	1,261,512	—	1,261,512
Other expenses	—	—	36,232	—
Total expenses	293,140	3,278,606	1,627,053	5,919,823
Loss before income taxes	(39,155)	(2,975,006)	(923,076)	(4,931,880)
Income tax benefit	(14,565)	(730,880)	(332,625)	(1,431,509)
Net loss	$ (24,590)	$ (2,244,126)	$ (590,451)	$ (3,500,371)
Net loss per common share				
Basic	$ (0.06)	$ (6.41)	$ (1.60)	$ (10.01)
Diluted	$ (0.06)	$ (6.41)	$ (1.60)	$ (10.01)
Dividends declared per common share	$ —	$ 0.0625	$ —	$ 0.1875
Weighted average common shares outstanding				
Basic	388,572	350,052	368,863	349,787
Diluted	388,572	350,052	368,863	349,787

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net loss	$ (24,590)	$ (2,244,126)	$ (590,451)	$ (3,500,371)
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $0, $11, $0, and $32, respectively	—	17	—	52
Total other comprehensive income	—	17	—	52
Comprehensive loss	$ (24,590)	$ (2,244,109)	$ (590,451)	$ (3,500,319)

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, 2016	Nine Months Ended September 30, 2015
Cash flows from operating activities		
Net loss	$ (590,451)	$ (3,500,371)
Adjustments to reconcile net loss to cash flows from operating activities		
Depletion, depreciation, and amortization	198,919	419,304
Write-down of oil and natural gas properties	810,921	3,612,600
Impairment of goodwill	—	1,261,512
Deferred income taxes	(331,574)	(1,432,572)
Stock-based compensation	9,682	22,637
Commodity derivatives expense (income)	99,811	(126,178)
Receipt on settlements of commodity derivatives	116,958	433,293
Gain on debt extinguishment	(115,095)	—
Debt issuance costs and discounts	15,541	6,810
Other, net	(3,271)	(7,457)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	(2,207)	57,867
Trade and other receivables	35,911	37,463
Other current and long-term assets	(8,434)	(1,771)
Accounts payable and accrued liabilities	(57,830)	(53,124)
Oil and natural gas production payable	(13,290)	(26,478)
Other liabilities	(6,232)	(4,138)
Net cash provided by operating activities	159,359	699,397
Cash flows from investing activities		
Oil and natural gas capital expenditures	(176,631)	(364,948)
Acquisitions of oil and natural gas properties	(560)	(21,171)
CO_2 capital expenditures	(467)	(21,894)
Pipelines and plants capital expenditures	(2,881)	(25,767)
Net proceeds from sales of oil and natural gas properties and equipment	47,232	327
Other	(700)	5,913
Net cash used in investing activities	(134,007)	(427,540)
Cash flows from financing activities		
Bank repayments	(1,362,500)	(1,491,000)
Bank borrowings	1,447,500	1,306,000
Repurchases of senior subordinated notes	(76,708)	—
Pipeline financing and capital lease debt repayments	(21,510)	(25,638)
Cash dividends paid	(478)	(65,422)
Other	(11,195)	(6,738)
Net cash used in financing activities	(24,891)	(282,798)
Net increase (decrease) in cash and cash equivalents	461	(10,941)
Cash and cash equivalents at beginning of period	2,812	23,153
Cash and cash equivalents at end of period	$ 3,273	$ 12,212

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.
Unaudited Condensed Consolidated Statement of Changes in Stockholders' Equity
(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		
	Shares	Amount			Shares	Amount	Total Equity
Balance – December 31, 2015	354,541,626	$ 355	$ 2,353,549	$ (1,058,954)	3,124,311	$ (46,038)	$ 1,248,912
Cumulative effect of accounting change	—	—	(415)	16,072	—	—	15,657
Issued or purchased pursuant to stock compensation plans	6,693,717	7	(7)	—	—	—	—
Issued pursuant to directors' compensation plan	31,930	—	50	—	—	—	50
Issued as part of debt exchange	40,729,332	40	160,451	—	—	—	160,491
Stock-based compensation	—	—	14,159	—	—	—	14,159
Tax withholding – stock compensation	—	—	—	—	764,986	(1,543)	(1,543)
Dividends adjustments	—	—	—	69	—	—	69
Net loss	—	—	—	(590,451)	—	—	(590,451)
Balance – September 30, 2016	401,996,605	$ 402	$ 2,527,787	$ (1,633,264)	3,889,297	$ (47,581)	$ 847,344

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is 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, 2015 (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, 2016, our consolidated results of operations for the three and nine months ended September 30, 2016 and 2015, our consolidated cash flows for the nine months ended September 30, 2016 and 2015, and our consolidated statement of changes in stockholders' equity for the nine months ended September 30, 2016.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. On the Unaudited Condensed Consolidated Balance Sheets, (1) debt issuance costs associated with our senior subordinated notes have been reclassified from "Other assets" to "Long-term debt, net of current portion" and (2) deferred tax assets have been reclassified from "Deferred tax assets, net" to "Deferred tax liabilities, net." Such reclassifications were made as a result of our adoption of new accounting pronouncements described in *Recent Accounting Pronouncements – Recently Adopted* below and had no impact on our previously reported net income or cash flows.

Net Loss per Common Share

Basic net loss per common share is computed by dividing the net loss attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net loss per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of nonvested restricted stock, stock appreciation rights ("SARs"), and nonvested performance-based equity awards. For the three and nine months ended September 30, 2016 and 2015, there were no adjustments to net loss for purposes of calculating basic and diluted net loss per common share.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2016	2015	2016	2015
Basic weighted average common shares outstanding	388,572	350,052	368,863	349,787
Potentially dilutive securities				
Restricted stock, SARs and performance-based equity awards	—	—	—	—
Diluted weighted average common shares outstanding	388,572	350,052	368,863	349,787

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 loss per common share (although time-vesting restricted stock is issued and outstanding upon grant).

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2016	2015	2016	2015
SARs	6,091	9,118	6,590	9,858
Restricted stock and performance-based equity awards	9,178	4,988	6,053	3,392

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 we do not have to incur additional costs to develop the proved oil and natural gas reserves. 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.

The average first-day-of-the-month NYMEX oil price used in estimating our proved reserves has followed a precipitous and continuing decline in oil prices throughout 2015 and the first nine months of 2016, and the average has declined from $59.21 per Bbl for the third quarter of 2015 to $41.68 per Bbl for the third quarter of 2016. In addition, the average first-day-of-the-month NYMEX natural gas price used in estimating our proved reserves was $3.04 per MMBtu for the third quarter of 2015 and $2.36 per MMBtu for the third quarter of 2016. These falling prices have led to our recognizing full cost pool ceiling test write-downs of $75.5 million, $479.4 million, and $256.0 million during the three months ended September 30, June 30, and March 31, 2016, respectively, and $1.8 billion, $1.7 billion, and $146.2 million during the three months ended September 30, June 30, and March 31, 2015, respectively.

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

2015 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. 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.

Recent Accounting Pronouncements

Recently Adopted

Stock Compensation. In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-09, *Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09"). ASU 2016-09 simplifies the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, and early adoption is permitted. The standard contains various amendments, each requiring a specific method of adoption, and designates whether each amendment should be adopted using a retrospective, modified retrospective, or prospective transition method. Effective January 1, 2016, we adopted ASU 2016-09. The amendments within ASU 2016-09 related to the timing of when excess tax benefits are recognized and accounting for forfeitures were adopted using a modified retrospective method. In accordance with this method, we recorded a cumulative-effect adjustment in our Unaudited Condensed Consolidated Balance Sheet on January 1, 2016, relating to the timing of recognition of excess tax benefits, representing a $15.7 million reduction to beginning "Accumulated deficit" with the offset to "Deferred tax liabilities, net" ($14.8 million) and "Other current assets" ($0.8 million). We also recorded a cumulative-effect adjustment in our Unaudited Condensed Consolidated Balance Sheet on January 1, 2016, to reflect actual forfeitures versus the previously-estimated forfeiture rate, representing a $0.4 million reduction to "Accumulated deficit" with the offset to "Paid-in capital in excess of par." The amendments within ASU 2016-09 related to the recognition of excess tax benefits and tax shortfalls in the income statement and presentation of excess tax benefits on the statement of cash flows were adopted prospectively, with no adjustments made to prior periods.

Income Taxes. In November 2015, the FASB issued ASU 2015-17, *Income Taxes* ("ASU 2015-17"). ASU 2015-17 simplifies the presentation of deferred income taxes and requires deferred tax assets and liabilities to be classified as noncurrent in the balance sheet. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, and early adoption is permitted. Entities can transition to the standard either retrospectively to each period presented or prospectively. Effective January 1, 2016, we adopted ASU 2015-17, which has been applied retrospectively for all comparative periods presented. Accordingly, current deferred tax assets of $1.5 million have been reclassified from "Deferred tax assets, net" to "Deferred tax liabilities, net" in our Unaudited Condensed Consolidated Balance Sheet as of December 31, 2015. The adoption of ASU 2015-17 did not have an impact on our consolidated results of operations or cash flows.

Debt Issuance Costs. In April 2015, the FASB issued 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. Entities are 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. Effective January 1, 2016, we adopted ASU 2015-03 and ASU 2015-15, which have been applied retrospectively for all comparative periods presented. Accordingly, debt issuance costs of $32.8 million associated with our previously issued senior subordinated notes have been reclassified from "Other assets" to "Long-term debt, net of current portion" in our Unaudited Condensed Consolidated Balance Sheet as of December 31, 2015. The adoption of ASU 2015-03 and ASU 2015-15 did not have an impact on our consolidated results of operations or cash flows for any periods.

Not Yet Adopted

Leases. In February 2016, the FASB issued ASU 2016-02, *Leases* ("ASU 2016-02"). ASU 2016-02 amends the guidance for lease accounting to require lease assets and liabilities to be recognized on the balance sheet, along with additional disclosures regarding key leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the standard using a modified retrospective transition and apply the guidance to the earliest comparative period presented, with certain practical expedients that entities may elect to apply. Management is currently assessing the impact the adoption of ASU 2016-02 will have on our consolidated financial statements.

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. In March, April and May 2016, the FASB issued four additional ASUs which primarily clarified the implementation guidance on principal versus agent considerations, performance obligations and licensing, collectibility, presentation of sales taxes and other similar taxes collected from customers, and non-cash consideration. 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 these standards will have on our consolidated financial statements.

Going Concern. In August 2014, the FASB issued ASU 2014-15, *Presentation of Financial Statements – Going Concern* ("ASU 2014-15"). ASU 2014-15 requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in United States auditing standards. The amendments in this ASU will be effective beginning in the fourth quarter of 2016, and for annual and interim periods thereafter. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations or cash flows.

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, 2016	December 31, 2015
Senior Secured Bank Credit Agreement	$ 260,000	$ 175,000
9% Senior Secured Second Lien Notes due 2021	614,919	—
6⅜% Senior Subordinated Notes due 2021	215,144	400,000
5½% Senior Subordinated Notes due 2022	772,912	1,250,000
4⅝% Senior Subordinated Notes due 2023	622,297	1,200,000
Other Subordinated Notes, including premium of $4 and $7, respectively	2,254	2,257
Pipeline financings	205,208	211,766
Capital lease obligations	55,189	71,324
Total debt principal balance	2,747,923	3,310,347
Future interest payable on 9% Senior Secured Second Lien Notes due 2021 [1]	254,660	—
Issuance costs on senior subordinated notes	(16,332)	(32,752)
Total debt, net of debt issuance costs on senior subordinated notes	2,986,251	3,277,595
Less: current maturities of long-term debt [1]	(83,200)	(32,481)
Long-term debt and capital lease obligations	$ 2,903,051	$ 3,245,114

(1) Future interest payable on our 9% Senior Secured Second Lien Notes due 2021 (the "2021 Senior Secured Notes") represents most of the interest due over the term of this obligation, which has been accounted for as debt in accordance with Financial Accounting Standards Board Codification ("FASC") 470-60, *Troubled Debt Restructuring by Debtors*. Our current maturities of long-term debt as of September 30, 2016 include $51.0 million of future interest payable related to the 2021 Senior Secured Notes that is due within the next twelve months. See *2016 Senior Subordinated Notes Exchange* below for further discussion.

The ultimate parent company in our corporate structure, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding senior secured second lien notes and 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 such notes are minor subsidiaries.

Senior Secured 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 maturity date of December 9, 2019. In October 2016, as part of our semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $1.05 billion, with the next such redetermination scheduled for May 2017.

In order to provide more flexibility in managing our balance sheet, the credit extended by our lenders, and continuing compliance with maintenance financial covenants in this low oil price environment, we entered into three amendments to the Bank Credit Agreement between May 2015 and April 2016 that modified the Bank Credit Agreement as follows:

- for 2016 and 2017, the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant has been suspended and replaced by a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 3.0 to 1.0 (only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio);
- for 2016 and 2017, a new covenant has been added to require a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0;
- beginning in the first quarter of 2018, the ratio of consolidated total net debt to consolidated EBITDAX covenant will be reinstated, utilizing an annualized EBITDAX amount for the first, second, and third quarters 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 ending March 31, 2018, 5.5 to 1.0 for the second quarter ending June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ending September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ending March 31, 2019;
- allows for the incurrence of up to $1.0 billion of junior lien debt (subject to customary requirements), with $385.1 million of future incurrence available as of September 30, 2016;
- limits unrestricted cash and cash equivalents to $225 million if more than $250 million of borrowings are outstanding under the Bank Credit Agreement; and
- limits the amount spent on repurchases or other redemptions of our senior subordinated notes to $225 million, with up to $148.3 million of this capacity remaining available as of September 30, 2016.

Additionally, such amendments made the following changes to the Bank Credit Agreement: (1) increased the applicable margin for ABR Loans and LIBOR Loans by 75 basis points such that the margin for ABR Loans now ranges from 1% to 2% per annum and the margin for LIBOR Loans now ranges from 2% to 3% per annum, (2) increased the commitment fee rate to 0.50%, and (3) provided for semiannual scheduled redeterminations of the borrowing base in May and November of each year. As of September 30, 2016, we were in compliance with all debt covenants under the Bank Credit Agreement. The weighted average interest rate on borrowings outstanding as of September 30, 2016, under the Bank Credit Agreement was 2.8%.

The above description of our Bank Credit Agreement financial covenants and the changes provided for within the three amendments are qualified by the express language and defined terms contained in the Bank Credit Agreement, the First Amendment to the Bank Credit Agreement dated May 4, 2015, the Second Amendment to the Bank Credit Agreement dated February 17, 2016, and the Third Amendment to the Bank Credit Agreement dated April 18, 2016, each of which are filed as exhibits to our periodic reports filed with the SEC.

2016 Senior Subordinated Notes Exchange

During May 2016, we entered into privately negotiated exchange agreements to exchange a total of $1,057.8 million of our existing senior subordinated notes for $614.9 million principal amount of our 2021 Senior Secured Notes plus 40.7 million shares of Denbury common stock, resulting in a net reduction from these exchanges of $442.9 million in our debt principal. The exchanged notes consisted of $175.1 million principal amount of our 6⅜% Senior Subordinated Notes due 2021 ("2021 Notes"), $411.0 million principal amount of our 5½% Senior Subordinated Notes due 2022 ("2022 Notes"), and $471.7 million principal amount of our 4⅝% Senior Subordinated Notes due 2023 ("2023 Notes").

In accordance with FASC 470-60, the exchanges were accounted for as a troubled debt restructuring due to the level of concession provided by our lenders. Under this guidance, future interest applicable to the 2021 Senior Secured Notes is recorded as debt up to the point that the principal and future interest of the new notes is equal to the principal amount of the extinguished notes, rather than recognizing a gain on extinguishment for this amount. As a result, $254.7 million of future interest on the 2021 Senior Secured Notes was recorded as debt, which will be reduced as semiannual interest payments are made, with the remaining $22.8 million of future interest to be recognized as interest expense over the term of these notes. Therefore, future interest expense reflected in our Unaudited Condensed Consolidated Statements of Operations on the 2021 Senior Secured Notes will be significantly lower than the actual cash interest payments. In addition, we recognized a gain of $12.0 million as a result of this debt exchange during the nine months ended September 30, 2016, which is included in "Gain on debt extinguishment" in the accompanying Unaudited Condensed Consolidated Statements of Operations.

9% Senior Secured Second Lien Notes due 2021

In May 2016, we issued $614.9 million of 2021 Senior Secured Notes. The 2021 Senior Secured Notes, which bear interest at a rate of 9% per annum, were issued at par in connection with privately negotiated exchanges with a limited number of holders of $1,057.8 million of existing senior subordinated notes (see *2016 Senior Subordinated Notes Exchange* above). The 2021 Senior Secured Notes mature on May 15, 2021, and interest is payable semiannually in arrears on May 15 and November 15 of each year, beginning November 15, 2016. We may redeem the 2021 Senior Secured Notes in whole or in part at our option beginning December 15, 2018, at a redemption price of 109% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture governing the 2021 Senior Secured Notes (the "Indenture"). Prior to December 15, 2018, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2021 Senior Secured Notes at a price of 109% of par with the proceeds of certain equity offerings. In addition, at any time prior to December 15, 2018, we may redeem the 2021 Senior Secured Notes in whole or in part at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 2021 Senior Secured Notes are not subject to any sinking fund requirements.

The Indenture contains customary covenants that restrict our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create limitations on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt (including existing senior subordinated notes)), provided that in certain circumstances we may make unlimited restricted payments so long as we maintain a ratio of total debt to EBITDA (as defined in the Indenture) not to exceed 2.5 to 1.0 (both before and after giving effect to any restricted payment).

The 2021 Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

2016 Repurchases of Senior Subordinated Notes

During the first quarter of 2016, we repurchased a total of $152.3 million of our outstanding long-term indebtedness, consisting of $4.0 million principal amount of our 2021 Notes, $42.3 million principal amount of our 2022 Notes, and $106.0 million principal amount of our 2023 Notes in open-market transactions for a total purchase price of $55.5 million, excluding accrued interest.

During the third quarter of 2016, we repurchased an additional $29.6 million of senior subordinated notes in open-market transactions, consisting of $5.8 million principal amount of our 2021 Notes and $23.8 million principal amount of our 2022 Notes, for a total purchase price of $21.2 million, excluding accrued interest. In connection with these series of transactions, we recognized a $103.1 million gain on extinguishment, net of unamortized debt issuance costs written off, during the nine months ended September 30, 2016. As of November 2, 2016, under the Bank Credit Agreement, up to an additional $148.3 million may be spent on repurchases or other redemptions of our 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, 2016, we had $34.5 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 tax valuation allowances totaling $33.6 million during 2015 and an additional $0.9 million during the first quarter of 2016, which reduced 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.

As of September 30, 2016, we had an unrecognized tax benefit of $5.4 million related to an uncertain tax position. The unrecognized tax benefit was recorded during the fourth quarter of 2015 as a direct reduction of the associated deferred tax asset and, if recognized, would not materially affect our annual effective tax rate. The tax benefit from an uncertain tax position will only be recognized if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. We currently do not expect a material change to the uncertain tax position within the next 12 months. Our policy is to recognize penalties and interest related to uncertain tax positions in income tax expense; however, no such amounts were accrued related to the uncertain tax position as of September 30, 2016.

In connection with the privately negotiated exchange agreements to exchange a portion of our existing senior subordinated notes for 2021 Senior Secured Notes, we realized a tax gain due to the concession extended by our note holders during the second quarter of 2016. This tax gain was offset by net operating losses and other deferred tax asset attributes.

Note 4. Stockholders' Equity

Dividends Declared During 2015

During the first three quarters of 2015, the Company's Board of Directors declared quarterly cash dividends of $0.0625 per common share, with dividends totaling $65.4 million paid to stockholders during the nine months ended September 30, 2015. In September 2015, in light of the continuing low oil price environment and our desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend.

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.

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, 2016, 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.

The following table summarizes our commodity derivative contracts as of September 30, 2016, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices ($/Bbl)					
				Weighted Average Price				
Months	Index Price	Volume (Barrels per day)	Range [1]		Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2016 Fixed-Price Swaps								
Oct – Dec	NYMEX	26,000	$ 36.25	– 45.40	$ 38.70	$ —	$ —	$ —
Oct – Dec	LLS	7,000	37.24	– 41.00	39.16	—	—	—
2016 Collars								
Oct – Dec	NYMEX	4,000	$ 40.00	– 54.00	$ —	$ —	$ 40.00	$ 53.48
Oct – Dec	LLS	4,000	40.00	– 56.00	—	—	40.00	55.79
2017 Fixed-Price Swaps								
Jan – Mar	NYMEX	22,000	$ 41.15	– 45.45	$ 42.67	$ —	$ —	$ —
Jan – Mar	LLS	10,000	42.35	– 46.15	43.77	—	—	—
Apr – June	NYMEX	22,000	41.20	– 46.50	43.99	—	—	—
Apr – June	LLS	7,000	42.65	– 46.65	45.35	—	—	—
2017 Collars								
Jan – Mar	NYMEX	4,000	$ 40.00	– 55.40	$ —	$ —	$ 40.00	$ 54.80
Jan – Mar	LLS	3,000	40.00	– 57.35	—	—	40.00	57.23
2017 Three-Way Collars [2]								
July – Sept	NYMEX	7,500	$ 40.00	– 70.25	$ —	$ 30.00	$ 40.00	$ 69.77
July – Sept	LLS	1,000	41.00	– 69.25	—	31.00	41.00	69.25

(1) Ranges presented for fixed-price 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.
(2) 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 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). Our costless collars and the sold put features of our 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.
- 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, 2016, instruments in this category include non-exchange-traded 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 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 $43 thousand in the fair value of these instruments as of September 30, 2016.

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, 2016				
Assets				
Oil derivative contracts – current	$ —	$ 302	$ 5	$ 307
Total Assets	$ —	$ 302	$ 5	$ 307
Liabilities				
Oil derivative contracts – current	$ —	$ 73,699	$ 530	$ 74,229
Total Liabilities	$ —	$ 73,699	$ 530	$ 74,229
December 31, 2015				
Assets				
Oil derivative contracts – current	$ —	$ 90,012	$ 52,834	$ 142,846
Total Assets	$ —	$ 90,012	$ 52,834	$ 142,846

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, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2016	2015	2016	2015
Fair value of Level 3 instruments, beginning of period	$ 240	$ 112,358	$ 52,834	$ 188,446
Fair value gains (losses) on commodity derivatives	2,402	21,089	(2,134)	38,872
Receipts on settlements of commodity derivatives	(3,167)	(50,573)	(51,225)	(144,444)
Fair value of Level 3 instruments, end of period	$ (525)	$ 82,874	$ (525)	$ 82,874
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets or liabilities still held at the reporting date	$ 891	$ 15,332	$ (525)	$ 25,456

We utilize an income approach to value our Level 3 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 9/30/2016 (in thousands)	Valuation Technique	Unobservable Input	Volatility Range
Oil derivative contracts	$ (525)	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after September 30, 2016	20.8%-40.8%

Other Fair Value Measurements

The carrying value of our 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 the fair value of our fixed-rate long-term debt using observable market data. The fair values of our senior secured second lien notes and senior subordinated notes are based on quoted market prices. The estimated fair value of the principal amount of our debt as of September 30, 2016 and December 31, 2015, excluding pipeline financing and capital lease obligations, was $2,010.3 million and $1,119.0 million, respectively, which increase is primarily driven by an increase in quoted market prices. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 7. Commitments and Contingencies

Commitments

In the second quarter of 2016, we amended our CO_2 offtake agreement with Mississippi Power Company ("MSPC"), which amendment included increasing our offtake percentage from 70% to 100% of CO_2 quantities produced and lowering the base price related to the cost of CO_2, deliveries of which are currently expected to begin in late 2016 or early 2017. Based on the amended terms in the agreement, we concluded for accounting purposes that the agreement contains an embedded lease related to the pipeline owned by MSPC used to transport CO_2 to Denbury. We currently plan to record a capital lease on the balance sheet of approximately $110 million upon lease commencement.

Litigation

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.

Settlement of NGS Sub Corp., Evolution, et al v. Denbury Onshore, LLC

During the second quarter of 2016, we settled the case brought by Evolution Petroleum Corporation (together with its subsidiaries, “Evolution”) involving the Delhi Field in northeastern Louisiana, resolving all outstanding disputes and claims the parties had or may have had against each other, including pending litigation claims.

Under the terms of the settlement agreement, (1) we paid Evolution $27.5 million in cash on June 30, 2016; (2) effective July 1, 2016, Denbury conveyed to Evolution 25% of the interests in the Mengel Sand Interval, a separate interval within the Delhi Unit which we purchased for approximately $6.5 million in late 2014, and which interval is not currently producing; (3) effective July 1, 2016, we were credited with an additional 0.2226% overriding royalty interest in the Holt-Bryant interval (the currently producing interval of the Delhi Unit); (4) the parties reached agreement as to the ownership of certain field assets, and established future CO_2 pipeline transportation charges following the end of the current ten-year fixed price arrangement set to expire in 2019; (5) Evolution waived and released any claims it may have to any insurance proceeds that may be received as a result of existing claims made by Denbury with respect to the June 2013 incident at Delhi Field; and (6) on July 11, 2016, the Court dismissed with prejudice the pending Delhi Field litigation between the parties. The cash payment was recorded to “Other expenses” in our Unaudited Condensed Consolidated Statements of Operations in the second quarter of 2016.

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 8. Additional Balance Sheet Details

Trade and Other Receivables, Net

In thousands	September 30, 2016	December 31, 2015
Trade accounts receivable, net	$ 24,890	$ 40,146
Commodity derivative settlement receivables	433	25,994
Other receivables	19,696	20,953
Total	$ 45,019	$ 87,093

Accounts Payable and Accrued Liabilities

In thousands	September 30, 2016	December 31, 2015
Accrued interest	$ 30,099	$ 48,908
Accounts payable	27,875	30,477
Accrued lease operating expenses	26,656	37,549
Accrued compensation	25,813	46,780
Taxes payable	25,386	32,438
Accrued exploration and development costs	6,309	20,892
Other	31,632	36,153
Total	$ 173,770	$ 253,197

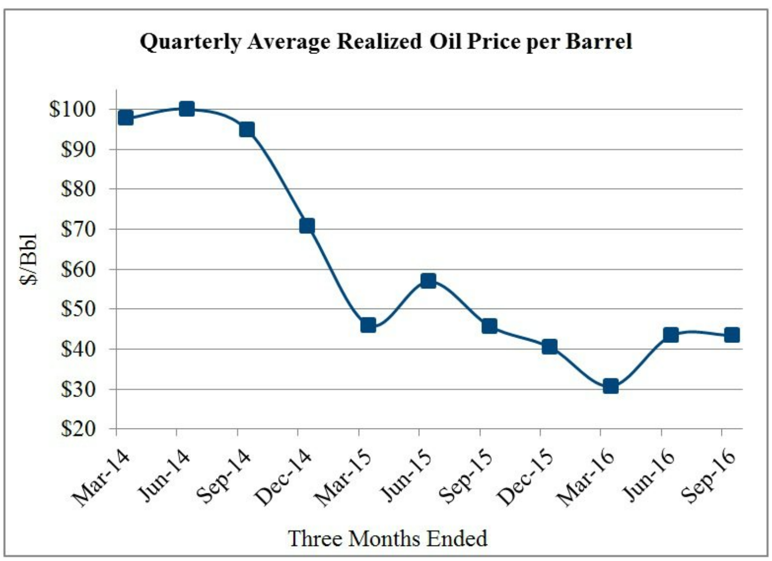
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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, 2015 (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. Oil prices have historically been volatile, with NYMEX prices ranging from $35 to $111 per Bbl over the last three calendar years, and declining to less than $27 per Bbl in January 2016, the lowest level in over 13 years, and an average of approximately $45 per Bbl in the third quarter of 2016. The following chart illustrates the fluctuations in our realized oil prices, excluding the impact of commodity derivative settlements, during 2014, 2015 and the first three quarters of 2016.



Quarterly average realized prices	Three Months Ended 3/31/14	6/30/14	9/30/14	12/31/14	3/31/15	6/30/15	9/30/15	12/31/15	3/31/16	6/30/16	9/30/16
Oil price per Bbl	$ 97.69	$100.04	$ 94.78	$ 70.80	$ 46.02	$ 56.92	$ 45.74	$ 40.41	$ 30.71	$ 43.38	$ 43.45

Although average second and third quarter oil prices in 2016 have increased from the lows experienced in the first quarter of 2016, our focus continues to remain on cost reductions and preserving liquidity. Cost reductions have been realized in all categories of our business in 2016. We previously set our 2016 capital development budget (excluding capitalized interest) at $200 million, which we expect to be primarily funded with cash flow from operations, thus preserving our liquidity. One advantage we have in this environment is that our oil assets have relatively low decline rates even with our significantly reduced planned capital spending level, and therefore we anticipate that our average daily production will decline by less than 10% in 2016, excluding the impact of weather-related downtime at Conroe and Thompson fields, completed asset sales, and production shut in for economic reasons. Lastly, we have hedged a portion of our estimated oil production through 2017 in order to cover our current level of cash costs and to help mitigate any future price declines or sustained low oil prices (see *Results of Operations – Commodity Derivative Contracts* below).

During this period of reduced capital spending, we have continued to evaluate our assets with a goal of increasing the value of both existing assets and future projects by optimizing field operational and development plans, reducing CO_2 injection volumes due to increased efficiency, and reducing costs such as power and workovers. We have reduced our overall CO_2 injection volumes by 35% and our total lease operating expenses by 20% (23% on a normalized basis – see *Results of Operations – Production Expenses – Lease Operating Expenses*) when comparing the nine months ended September 30, 2016 and 2015. These initiatives aim to increase the profitability of our assets, making them more resilient to lower oil prices. Together, we believe these initiatives will help us manage through this low oil price environment.

2016 Debt Reduction Transactions. During 2016, we have completed a series of privately negotiated exchange agreements and open-market transactions, contributing to a net reduction of our debt principal balance of approximately $562 million between December 31, 2015 and September 30, 2016. In May 2016, we exchanged $1,057.8 million of existing senior subordinated notes with a limited number of holders for $614.9 million of our new 9% Senior Secured Second Lien Notes due 2021 (the "2021 Senior Secured Notes") plus 40.7 million shares of Denbury common stock, resulting in a net reduction from these exchanges of $442.9 million in our debt principal. During the first nine months of 2016, we repurchased $181.9 million of our existing senior subordinated notes for $76.7 million in open-market transactions, for a net reduction of $105.2 million of our debt principal. See *Capital Resources and Liquidity – 2016 Debt Reduction Transactions* for further discussion.

2016 Divestiture of Non-Core Assets. On August 31, 2016, we completed the sale of certain non-core assets in the Williston Basin of North Dakota and Montana (the "Williston Assets") for $58 million (before closing adjustments). The sale had an effective date of April 1, 2016, and proceeds realized after closing adjustments totaled $53.6 million. Approximately $9 million of proceeds from the sale of Williston Assets was paid by the purchaser directly to a qualified intermediary to facilitate a like-kind-exchange, and are therefore not reflected as an investing activity on our Unaudited Condensed Consolidated Statements of Cash Flows.

Operating Highlights. Realized oil prices were relatively consistent on a sequential quarter basis between the second and third quarters of 2016 and only slightly less than the third quarter of 2015. However, during 2015 and, to a lesser extent, the first half of 2016, we had strong in-the-money hedges offsetting a portion of the effect of low oil prices, collecting $160.7 million on these hedges in the third quarter of 2015 and $52.0 million during the second quarter of 2016. Proceeds from hedges settling during the third quarter of 2016 were not as strong, resulting in a $10 per-barrel decrease in our realized oil prices after hedges when compared to those in the second quarter of 2016, and a $29 per-barrel decrease when compared to the third quarter of 2015. This net realized price decline resulted in lower cash flows during the third quarter of 2016 when compared to the third quarter of 2015.

In spite of the lower realized oil prices discussed above, our net loss in the third quarter of 2016 decreased due to the substantial decrease in noncash impairments, primarily because the oil price began to stabilize somewhat and the trailing 12-month average price (the primary driver of the value of our proved reserves and therefore any full cost pool ceiling test write-downs) declined only slightly between the second and third quarters of 2016. The full cost pool ceiling test write-down of our oil and natural gas properties totaled $75.5 million ($48.4 million net of tax) in the third quarter of 2016, compared to $1.8 billion ($1.1 billion net of tax) in the third quarter of 2015 (see *Results of Operations – Write-Down of Oil and Natural Gas Properties* below), and during the third quarter of 2015 we also recorded a goodwill impairment charge of $1.3 billion ($1.2 billion net of tax) (see *Results of Operations – 2015 Impairment of Goodwill* below). This significant difference in impairments reduced our net loss during the third quarter of 2016 to $24.6 million, or $0.06 per diluted common share, compared to a net loss of $2.2 billion, or $6.41 per diluted common share, during the third quarter of 2015.

We generated $96.4 million of cash flows from operating activities in the third quarter of 2016, an increase of $35.5 million from the $60.9 million generated in the second quarter of 2016. The sequential increase in cash flows from operations was due primarily to positive impacts from working capital changes ($66.9 million) and the second quarter Evolution settlement ($27.5 million), partially offset by a decline in derivative settlements ($59.3 million). When compared to the prior year third quarter, cash flows from operating activities decreased $176.3 million from $272.7 million, due primarily to a $168.0 million decline in derivative settlements and lower oil prices and production volumes, which caused a decrease in oil revenues, partially offset by reductions in operating expenses.

During the third quarter of 2016, our oil and natural gas production, which was 96% oil, averaged 61,533 BOE/d, compared to an average of 71,410 BOE/d produced during the third quarter of 2015 and 64,506 BOE/d during the second quarter of 2016. Declines during these comparative periods were significantly impacted by weather-related shut-in production, facility downtime, maintenance and repair work, and natural production declines based on our lower capital spending level, with the year-over-year declines further impacted by production shut in due to economics. Total production also includes production from the Williston Assets which were sold during the third quarter of 2016 and other property divestitures. Production related to the Williston Assets and other property divestitures averaged 819 BOE/d in the third quarter of 2016, compared to 1,957 BOE/d during the third quarter of 2015 and 1,530 BOE/d during the second quarter of 2016. These production decreases were partially offset by increases in production due to continued CO_2 enhanced oil recovery response at Delhi Field in the Gulf Coast region, with the year-over-year decrease further offset by production increases at Bell Creek Field in the Rocky Mountain region. See *Results of Operations – Production* for further discussion.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, was $43.45 per Bbl during the third quarter of 2016, a decrease of 5% compared to $45.74 per Bbl realized during the third quarter of 2015 and consistent with the average price received during the second quarter of 2016. The oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) was $1.57 per Bbl below NYMEX prices in the third quarter of 2016, compared to a negative $0.96 per-Bbl NYMEX differential in the third quarter of 2015 and a negative $2.18 per-Bbl NYMEX differential in the second quarter of 2016. The weakening in our oil price differential in comparison to its level in the third quarter of 2015 was principally due to weakening of our Light Louisiana Sweet ("LLS") premium relative to NYMEX oil prices.

One of our primary focuses in the past few years has been to reduce costs throughout the organization through a number of internal initiatives. As a result of these efforts, we have been able to achieve reductions in our lease operating expenses, with total lease operating expenses of $309.0 million during the nine months ended September 30, 2016, a 20% reduction when compared to the prior year period (a 23% reduction when normalized to eliminate the effect of special or unusual items in the prior-year period). Excluding special or unusual amounts reported in 2015, total lease operating expenses per BOE during the nine months ended September 30, 2016 were $17.32, compared to $20.08 during the same prior year period, with decreases realized in most categories of lease operating expenses. On a sequential-quarter basis, lease operating expenses per BOE increased 10% from the second quarter of 2016 primarily due to both a 5% decline in production and higher repair costs at Thompson Field attributable to work done to bring the field back to production during the third quarter of 2016. General and administrative expenses per BOE increased 13% from the second quarter of 2016 due to the decline in production and higher employee-related costs due to our annual long-term incentive grants being made during the third quarter of 2016 rather than in the first quarter as in years past.

Grieve Field Revised Joint Venture. On August 4, 2016, the Company and its joint venture partner in Grieve Field, located in Wyoming, reached an agreement to revise the joint venture arrangement between the parties for the continued development of such field. The revised agreement provides for our partner to fund the remaining estimated capital of $55 million to complete development of the facility and fieldwork in exchange for a 14% higher working interest and a disproportionate sharing of revenue during the first 2 million barrels of production. As a result of this agreement, our working interest in the field was reduced from 65% to 51%. This arrangement will accelerate the remaining development of the facility and fieldwork, which we now anticipate should be complete by the middle of 2018.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability of borrowing capacity under our senior secured bank credit facility. As a result of the significant reduction in oil prices discussed above and less advantageous hedge positions, our cash flow from operations has significantly decreased, from $699.4 million during the nine months ended September 30, 2015, to $159.4 million during the nine months ended September 30, 2016.

The preservation of cash and liquidity remains a significant priority for us in the current oil price environment. We have taken steps to lower our costs in all categories of our business, and we have made significant progress in that regard. Over the past year, we have also amended our bank credit facility to relax certain bank covenants through 2018 (see *Senior Secured Bank Credit Facility* below). As of September 30, 2016, we had $260.0 million drawn on our $1.05 billion senior secured bank credit facility, leaving us $714.7 million of current liquidity after consideration of $75.3 million of outstanding letters of credit. This liquidity, coupled with our other cost saving and liquidity preservation measures, should be sufficient to cover any cash flow shortfall and fund our capital and operating cash outflows during this low oil price environment.

In order to provide a level of price protection to a portion of our oil production, we have entered into a combination of oil swaps, collars, and three-way collars for the fourth quarter of 2016 and throughout 2017 (see *Results of Operations – Commodity Derivative Contracts* below). While a portion of these derivatives entered into in early 2016 are fixed-price swaps at prices that do not support capital spending levels which would grow our production, they do at least cover our most recent total cash costs, which were in a per-barrel range in the low-to-mid $30's in the third quarter of 2016, including corporate overhead and interest, thereby minimizing the amount that would be required for day-to-day operations from our bank credit facility.

Since we do not expect oil prices to recover in the foreseeable future to recent historical highs of 2014, we must adjust our business to compete in an oil price environment that is likely not as robust as it was a few years ago, requiring reductions in overall debt levels over time. We have made significant progress in this endeavor during 2016 with a net reduction in our debt principal of $562 million through September 30, 2016 (see Note 2, *Long-Term Debt*, to the Unaudited Condensed Consolidated Financial Statements), and we would like to find other ways to reduce our debt. Our subordinated debt is currently trading higher than it was during the first half of 2016, making it more difficult to make accretive exchanges or repurchases of this debt. We would like to reduce our debt further if possible, and we plan to monitor the market and be opportunistic in our debt transactions based upon market conditions. These potential transactions could include purchases of our subordinated debt in the open market, cash tenders for our debt or public or privately-negotiated debt exchanges, and future potential debt reduction with proceeds of issuances of equity, asset sales and other cash-generating activities. We may utilize a portion of the availability under our bank credit facility for such repurchases and may also consider other forms of capital such as additional second lien notes or other senior notes.

Senior Secured 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"). In October 2016, as part of our semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $1.05 billion, with our next borrowing base redetermination scheduled for May 2017. As of September 30, 2016, we had $260.0 million of debt outstanding and $75.3 million in letters of credit on the senior secured bank credit facility. In order to provide more flexibility in managing our balance sheet, the credit extended by our lenders, and continuing compliance with maintenance financial covenants in this low oil price environment, we entered into three amendments to the Bank Credit Agreement between May 2015 and April 2016 that modified the Bank Credit Agreement as follows:

- for 2016 and 2017, the maximum permitted ratio of consolidated total net debt to consolidated EBITDAX covenant has been suspended and replaced by a maximum permitted ratio of consolidated senior secured debt to consolidated EBITDAX covenant of 3.0 to 1.0 (only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio);
- for 2016 and 2017, a new covenant has been added to require a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0;
- beginning in the first quarter of 2018, the ratio of consolidated total net debt to consolidated EBITDAX covenant will be reinstated, utilizing an annualized EBITDAX amount for the first, second, and third quarters 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 ending March 31, 2018, 5.5 to 1.0 for the second quarter ending June 30, 2018, and 5.0 to 1.0 for the third and fourth quarters ending September 30 and December 31, 2018, and returning to 4.25 to 1.0 for the first quarter ending March 31, 2019;
- allows for the incurrence of up to $1.0 billion of junior lien debt (subject to customary requirements), with $385.1 million of future incurrence available as of September 30, 2016;
- limits unrestricted cash and cash equivalents to $225 million if more than $250 million of borrowings are outstanding under the Bank Credit Agreement; and
- limits the amount spent on repurchases or other redemptions of our senior subordinated notes to $225 million, with up to $148.3 million of this capacity remaining available as of September 30, 2016.

For these financial performance covenant calculations as of September 30, 2016, our ratio of consolidated senior secured debt to consolidated EBITDAX was 0.52 to 1.0, our ratio of consolidated EBITDAX to consolidated interest charges was 2.88 to 1.0, and our current ratio was 3.54. Based upon our currently forecasted levels of production and costs, hedges in place as of November 2, 2016, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our bank covenants during the remainder of 2016 and 2017.

The above description of our Bank Credit Agreement financial covenants and the changes provided for within the three amendments are qualified by the express language and defined terms contained in the Bank Credit Agreement, the First Amendment to the Bank Credit Agreement dated May 4, 2015, the Second Amendment to the Bank Credit Agreement dated February 17, 2016, and the Third Amendment to the Bank Credit Agreement dated April 18, 2016, each of which are filed as exhibits to our periodic reports filed with the SEC.

2016 Debt Reduction Transactions. During 2016, we have completed a series of privately negotiated debt exchange agreements and open-market debt repurchase transactions, contributing to a net reduction of our debt principal balance of approximately $562 million between December 31, 2015 and September 30, 2016. During May 2016, we entered into privately negotiated exchange agreements to exchange $175.1 million principal amount of our 6⅜% Senior Subordinated Notes due 2021 ("2021 Notes"), $411.0 million principal amount of our 5½% Senior Subordinated Notes due 2022 ("2022 Notes"), and $471.7 million principal amount of our 4⅝% Senior Subordinated Notes due 2023 ("2023 Notes") for $614.9 million principal amount of new 2021 Senior Secured Notes plus 40.7 million shares of Denbury common stock, resulting in a net reduction from these exchanges of $442.9 million in our debt principal. Our Bank Credit Agreement allows for the incurrence of up to $1.0 billion of junior lien debt, so after taking these exchanges into account, we have an additional $385.1 million of junior lien debt capacity that remains available to us.

During the first quarter of 2016, we repurchased a total of $152.3 million principal amount of our existing senior subordinated notes in open-market transactions, consisting of $4.0 million principal amount of our 2021 Notes, $42.3 million principal amount of our 2022 Notes, and $106.0 million principal amount of our 2023 Notes for a total purchase price of $55.5 million, excluding accrued interest. During the third quarter of 2016, we repurchased an additional $29.6 million of senior subordinated notes in open-market transactions, consisting of $5.8 million principal amount of our 2021 Notes and $23.8 million principal amount of our 2022 Notes for a total purchase price of $21.2 million, excluding accrued interest. The repurchases were made at prices ranging from approximately 25% to 75% of the principal amount of the individual senior subordinated notes. In connection with these series of transactions, we recognized a $103.1 million gain on debt extinguishment, net of unamortized debt issuance costs written off, during the nine months ended September 30, 2016. We currently estimate combined annual cash interest savings of approximately $7 million related to these repurchases and the exchange transactions. Our Bank Credit Agreement limits open-market repurchases of our senior subordinated notes to $225 million, and as of November 2, 2016, we have up to $148.3 million of remaining capacity for senior subordinated notes repurchases or other redemptions.

Capital Spending. We anticipate that our full-year 2016 capital budget, excluding capitalized interest and acquisitions, will be approximately $200 million, which includes approximately $55 million in capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs. This combined 2016 capital budget amount, excluding capitalized interest and acquisitions, is comprised of the following:

- $110 million allocated for tertiary oil field expenditures;
- $30 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $5 million to be spent on CO_2 sources and pipeline construction; and
- $55 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Based upon our currently forecasted levels of production and costs, commodity hedges in place, and current oil commodity futures prices, we intend to fund our development capital spending primarily with cash flow from operations, with any potential shortfall funded with incremental borrowings under our senior secured bank credit facility, and as of September 30, 2016, we had ample availability on our senior secured bank credit facility to cover any foreseeable cash flow shortfall.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the nine months ended September 30, 2016 and 2015:

	Nine Months Ended September 30,	
In thousands	2016	2015
Capital expenditures by project		
Tertiary oil fields	$ 90,392	$ 133,439
Non-tertiary fields	19,142	75,199
Capitalized internal costs [(1)]	35,516	50,220
Oil and natural gas capital expenditures	145,050	258,858
CO_2 pipelines	473	10,135
CO_2 sources	335	17,686
Other	20	603
Capital expenditures, before acquisitions and capitalized interest	145,878	287,282
Acquisitions of oil and natural gas properties	10,888	22,755
Capital expenditures, before capitalized interest	156,766	310,037
Capitalized interest	18,944	25,228
Capital expenditures, total	$ 175,710	$ 335,265

(1) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

For the nine months ended September 30, 2016, our capital expenditures and property acquisitions were primarily funded with $159.4 million of cash flows from operations, with additional funds provided by asset sales and borrowings on our senior secured bank credit facility. For the nine months ended September 30, 2015, our capital expenditures and property acquisitions were fully funded with cash flows from operations.

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.

In the second quarter of 2016, we amended our CO_2 offtake agreement with Mississippi Power Company ("MSPC"), which amendment included increasing our offtake percentage from 70% to 100% of CO_2 quantities produced and lowering the base price related to the cost of CO_2, deliveries of which are currently expected to begin in late 2016 or early 2017. Based on the amended terms in the agreement, we concluded for accounting purposes that the agreement contains an embedded lease related to the pipeline owned by MSPC used to transport CO_2 to Denbury. We currently plan to record a capital lease on the balance sheet of approximately $110 million upon lease commencement.

Our commitments and obligations consist of those detailed as of December 31, 2015, 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.

Operating Results Table

Certain of our operating results and statistics for the comparative three and nine months ended September 30, 2016 and 2015 are included in the following table:

In thousands, except per-share and unit data	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating results				
Net income (loss) [1]	$ (24,590)	$ (2,244,126)	$ (590,451)	$ (3,500,371)
Net income (loss) per common share – basic [1]	(0.06)	(6.41)	(1.60)	(10.01)
Net income (loss) per common share – diluted [1]	(0.06)	(6.41)	(1.60)	(10.01)
Dividends declared per common share	—	0.0625	—	0.1875
Net cash provided by operating activities	96,415	272,676	159,359	699,397
Average daily production volumes				
Bbls/d	59,297	67,900	62,451	69,424
Mcf/d	13,416	21,066	15,995	22,357
BOE/d [2]	61,533	71,410	65,117	73,150
Operating revenues				
Oil sales	$ 237,053	$ 285,742	$ 666,441	$ 939,744
Natural gas sales	2,877	4,646	7,960	15,005
Total oil and natural gas sales	$ 239,930	$ 290,388	$ 674,401	$ 954,749
Commodity derivative contracts [3]				
Receipt (payment) on settlements of commodity derivatives	$ (7,295)	$ 160,677	$ 116,958	$ 433,293
Noncash fair value gains (losses) on commodity derivatives [4]	28,519	(68,649)	(216,769)	(307,115)
Commodity derivatives income (expense)	$ 21,224	$ 92,028	$ (99,811)	$ 126,178
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 43.45	$ 45.74	$ 38.95	$ 49.58
Natural gas price per Mcf	2.33	2.40	1.82	2.46
Unit prices – including impact of derivative settlements [3]				
Oil price per Bbl	$ 42.12	$ 71.32	$ 45.78	$ 72.31
Natural gas price per Mcf	2.33	2.87	1.82	2.89
Oil and natural gas operating expenses				
Lease operating expenses [5]	$ 106,522	$ 113,902	$ 308,988	$ 387,156
Marketing expenses, net of third-party purchases, and plant operating expenses	11,225	12,606	33,707	34,943
Production and ad valorem taxes	17,983	20,989	52,201	73,606
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$ 42.38	$ 44.20	$ 37.80	$ 47.81
Lease operating expenses [5]	18.82	17.34	17.32	19.39
Marketing expenses, net of third-party purchases, and plant operating expenses	1.99	1.91	1.89	1.75
Production and ad valorem taxes	3.18	3.19	2.93	3.69
CO_2 sources – revenues and expenses				
CO_2 sales and transportation fees	$ 6,253	$ 9,144	$ 19,147	$ 23,268
CO_2 discovery and operating expenses	(861)	(1,017)	(2,539)	(2,909)
CO_2 revenue and expenses, net	$ 5,392	$ 8,127	$ 16,608	$ 20,359

(1) Includes full cost pool ceiling test write-downs of $75.5 million and $810.9 million for the three and nine months ended September 30, 2016, respectively, and $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 gains (losses) 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 gains (losses) on commodity derivatives represent only the net changes between periods of the fair market values of commodity derivative positions, and exclude the impact of settlements on commodity derivatives during the period, which were payments on settlements of $7.3 million for the three months ended September 30, 2016 and receipts on settlements of $117.0 million for the nine months ended September 30, 2016, compared to receipts on settlements of $160.7 million and $433.3 million for the three and nine months ended September 30, 2015, respectively. We believe that noncash fair value gains (losses) on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from receipts or payments upon settlements on commodity derivatives during the periods presented. 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 (loss) to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value gains (losses) 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 special items for the three and nine months ended September 30, 2015, that had the effect of reducing lease operating expenses on a net basis, comprised of (1) lease operating expenses and related insurance recoveries recorded to remediate an area of Delhi Field ($3.2 million) (see *Production Expenses – Lease Operating Expense*), (2) a reimbursement for a retroactive utility rate adjustment ($9.6 million), and (3) other insurance recoveries ($0.9 million). If these special items are excluded, lease operating expenses would have increased to $127.6 million and $400.9 million for the three and nine months ended September 30, 2015, respectively, and lease operating expense per BOE would have increased to an average of $19.43 and $20.08 for the three and nine months ended September 30, 2015, respectively.

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

Production

Average daily production by area for each of the four quarters of 2015 and for the first, second, and third quarters of 2016 is shown below:

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2015	Second Quarter 2015	Third Quarter 2015	Fourth Quarter 2015	First Quarter 2016	Second Quarter 2016	Third Quarter 2016
Tertiary oil production							
Gulf Coast region							
Mature properties [(1)]	10,801	11,170	10,946	10,403	9,666	9,415	8,653
Delhi	3,551	3,623	3,676	3,898	3,971	3,996	4,262
Hastings	4,694	5,350	5,114	5,082	5,068	4,972	4,729
Heidelberg	6,027	5,885	5,600	5,635	5,346	5,246	5,000
Oyster Bayou	5,861	5,936	5,962	5,831	5,494	5,088	4,767
Tinsley	8,928	8,740	7,311	7,522	7,899	7,335	6,756
Total Gulf Coast region	39,862	40,704	38,609	38,371	37,444	36,052	34,167
Rocky Mountain region							
Bell Creek	1,965	1,880	2,225	2,806	3,020	3,160	3,032
Total Rocky Mountain region	1,965	1,880	2,225	2,806	3,020	3,160	3,032
Total tertiary oil production	41,827	42,584	40,834	41,177	40,464	39,212	37,199
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	1,301	943	1,157	1,377	673	1,017	963
Texas	6,490	6,304	6,508	6,470	6,148	4,104	4,234
Other	1,006	906	846	800	549	456	538
Total Gulf Coast region	8,797	8,153	8,511	8,647	7,370	5,577	5,735
Rocky Mountain region							
Cedar Creek Anticline	18,522	18,089	17,515	17,875	17,778	16,325	16,017
Other	3,107	2,872	2,593	2,407	2,070	1,862	1,763
Total Rocky Mountain region	21,629	20,961	20,108	20,282	19,848	18,187	17,780
Total non-tertiary production	30,426	29,114	28,619	28,929	27,218	23,764	23,515
Total continuing production	72,253	71,698	69,453	70,106	67,682	62,976	60,714
Property sales							
Williston Assets [(2)]	1,643	1,561	1,522	1,473	1,364	1,267	819
Other property divestitures	460	457	435	423	305	263	—
Total production	74,356	73,716	71,410	72,002	69,351	64,506	61,533

(1) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Lockhart Crossing, Mallalieu, Martinville, McComb and Soso fields.

(2) Includes non-tertiary production in the Rocky Mountain region related to the sale of remaining non-core assets in the Williston Basin of North Dakota and Montana, which closed in the third quarter of 2016.

Total Production

Total continuing production during the third quarter of 2016 averaged 60,714 BOE/d, including 37,199 Bbls/d from tertiary properties and 23,515 BOE/d from non-tertiary properties. This total continuing production level represents a decrease of 2,262 BOE/d (4%) compared to second quarter of 2016 production levels and a decrease of 8,739 BOE/d (13%) compared to third quarter of 2015 production levels. Total continuing production excludes production from the Williston Assets that were sold during the third quarter of 2016 and other minor property divestitures, totaling 819 BOE/d during the third quarter of 2016, compared to 1,530 BOE/d during the second quarter of 2016 and 1,957 BOE/d during the third quarter of 2015. Third quarter of 2016 production continued to be impacted by the weather-related downtime at Thompson and Conroe fields due to flooding and damage caused by strong thunderstorms in the Houston area during April and May this year; however, both fields were largely returned to full production by the end of September, and combined production from these two fields was relatively flat sequentially. Most of the sequential quarterly production decline was related to our tertiary production, which was impacted to some degree by unplanned downtime at some fields and a planned facility turnaround at Tinsley Field. This production decline was offset in part by continued tertiary production growth at Delhi Field.

In reviewing the 13% decline in continuing production from the third quarter of 2015, approximately one-half of the production decline was due to weather-related shut-in production at Thompson and Conroe fields, planned facility downtime at Tinsley Field and unplanned downtime at other fields. The remaining decline is largely due to natural production declines; although we have some inclining production at our fields, we are not currently investing sufficient capital to hold production flat.

As of September 30, 2016, we estimate that approximately 2,000 BOE/d of production remained shut in attributable to uneconomic wells, a reduction of approximately 600 BOE/d from June 30, 2016 levels, primarily due to the Williston Asset sale, in addition to minor production volumes returned to production during the quarter. Our production during the three and nine months ended September 30, 2016 was 96% oil, consistent with 95% oil production during the three and nine months ended September 30, 2015.

Tertiary Production

Oil production from our tertiary operations during the third quarter of 2016 decreased 2,013 Bbls/d (5%) sequentially and 3,635 Bbls/d (9%) compared to the same period in 2015. These decreases were primarily due to facility downtime at Tinsley Field, unplanned compressor downtime at Oyster Bayou Field, and natural production declines at our mature fields in the Gulf Coast region, partially offset by increased production due to continued CO_2 enhanced oil recovery response at Delhi Field in the Gulf Coast region. The year-over-year decline was further offset by increased production at Bell Creek Field in the Rocky Mountain region.

Non-Tertiary Production

Continuing production from our non-tertiary operations averaged 23,515 BOE/d during the third quarter of 2016, a decrease of 249 BOE/d (1%) sequentially and a decrease of 5,104 BOE/d (18%) compared to the third quarter of 2015 levels. The year-over-year production declines include weather-related downtime at Conroe and Thompson fields, as noted above, and production attributable to wells shut in as uneconomic to either produce or repair due to commodity prices. When combined, these weather-related downtime and shut-in production impacts resulted in a quarterly production decline of approximately 3,000 BOE/d when compared to prior year. In addition, the sequential and year-over-year changes include natural production declines at our non-tertiary properties in the Rocky Mountain and Gulf Coast regions.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and nine months ended September 30, 2016 decreased 17% and 29%, respectively, compared to these revenues for the same periods in 2015. The changes in our oil and natural gas revenues are due to changes in production quantities and commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

	Three Months Ended September 30, 2016 vs. 2015		Nine Months Ended September 30, 2016 vs. 2015	
In thousands	Decrease in Revenues	Percentage Decrease in Revenues	Decrease in Revenues	Percentage Decrease in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$ (40,167)	(14)%	$ (101,734)	(11)%
Decrease in commodity prices	(10,291)	(3)%	(178,614)	(18)%
Total decrease in oil and natural gas revenues	$ (50,458)	(17)%	$ (280,348)	(29)%

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, 2016 and 2015:

	Three Months Ended March 31, 2016	March 31, 2015	June 30, 2016	June 30, 2015	September 30, 2016	September 30, 2015	Nine Months Ended September 30, 2016	September 30, 2015
Average net realized prices:								
Oil price per Bbl	$ 30.71	$ 46.02	$ 43.38	$ 56.92	$ 43.45	$ 45.74	$ 38.95	$ 49.58
Natural gas price per Mcf	1.70	2.54	1.50	2.44	2.33	2.40	1.82	2.46
Price per BOE	29.76	44.45	42.02	54.69	42.38	44.20	37.80	47.81
Average NYMEX differentials:								
Oil per Bbl	$ (3.02)	$ (2.81)	$ (2.18)	$ (0.89)	$ (1.57)	$ (0.96)	$ (2.51)	$ (1.52)
Natural gas per Mcf	(0.29)	(0.28)	(0.73)	(0.30)	(0.47)	(0.34)	(0.53)	(0.30)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, decreased 5% during the third quarter of 2016 from the average price received during the third quarter of 2015 and was consistent with the average price received during the second quarter of 2016. Company-wide average oil price differentials in the third quarter of 2016 were $1.57 per Bbl below NYMEX, compared to an average differential of $0.96 per Bbl below NYMEX in the third quarter of 2015 and $2.18 per Bbl below NYMEX in the second quarter of 2016. The change versus prior year was principally due to weakening of our Gulf Coast region LLS price differentials, offset in part by Rocky Mountain region price differentials described below. 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 negative $0.77 per Bbl and a positive $0.92 per Bbl during the three months ended September 30, 2016 and 2015, respectively, and a negative $1.22 per Bbl during the three months ended June 30, 2016. 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 $1.73 per Bbl in the third quarter of 2016, down from a positive $3.89 per Bbl in the third quarter of 2015 and down from a positive $2.04 per Bbl in the second quarter of 2016. During the third quarter of 2016, we sold approximately 60% of our crude oil at prices based on, or 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.

NYMEX oil differentials in the Rocky Mountain region averaged $3.08 per Bbl and $4.73 per Bbl below NYMEX during the three months ended September 30, 2016 and 2015, respectively, and $3.98 per Bbl below NYMEX during the three months ended June 30, 2016. 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.

Commodity Derivative Contracts

The following table summarizes the impact our oil and natural gas derivative contracts had on our operating results for the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30,					
	2016	2015	2016	2015	2016	2015
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Receipt (payment) on settlements of commodity derivatives	$ (7,295)	$ 159,770	$ —	$ 907	$ (7,295)	$ 160,677
Noncash fair value gains (losses) on commodity derivatives (1)	28,519	(68,054)	—	(595)	28,519	(68,649)
Total income	$ 21,224	$ 91,716	$ —	$ 312	$ 21,224	$ 92,028

	Nine Months Ended September 30,					
	2016	2015	2016	2015	2016	2015
In thousands	Crude Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Receipt on settlements of commodity derivatives	$ 116,958	$ 430,669	$ —	$ 2,624	$ 116,958	$ 433,293
Noncash fair value losses on commodity derivatives (1)	(216,769)	(305,198)	—	(1,917)	(216,769)	(307,115)
Total income (expense)	$ (99,811)	$ 125,471	$ —	$ 707	$ (99,811)	$ 126,178

(1) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

Denbury Resources Inc.

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

In order to provide a level of price protection to a portion of our oil production, we have entered into a combination of oil swaps, collars, and three-way collars for the fourth quarter of 2016 and throughout 2017. The following table summarizes our commodity derivative contracts as of November 2, 2016:

		4Q16	1Q17	2Q17	3Q17	4Q17
WTI NYMEX	Volumes Hedged (Bbls/d)	26,000	22,000	22,000	—	—
Fixed-Price Swaps	Swap Price [1]	$38.70	$42.67	$43.99	—	—
Argus LLS	Volumes Hedged (Bbls/d)	7,000	10,000	7,000	—	—
Fixed-Price Swaps	Swap Price [1]	$39.16	$43.77	$45.35	—	—
WTI NYMEX	Volumes Hedged (Bbls/d)	4,000	4,000	—	—	—
Collars	Ceiling Price / Floor [1]	$53.48 / $40	$54.80 / $40	—	—	—
WTI NYMEX	Volumes Hedged (Bbls/d)	—	—	—	13,500	7,000
3-Way Collars	Ceiling Price / Floor / Sold Put Price [1][2]	—	—	—	$69.13 / $40 / $30	$69.45 / $40 / $30
Argus LLS	Volumes Hedged (Bbls/d)	4,000	3,000	—	—	—
Collars	Ceiling Price / Floor [1]	$55.79 / $40	$57.23 / $40	—	—	—
Argus LLS	Volumes Hedged (Bbls/d)	—	—	—	2,000	1,000
3-Way Collars	Ceiling Price / Floor / Sold Put Price [1][2]	—	—	—	$69.25 / $41 / $31	$70.25 / $41 / $31
	Total Volumes Hedged (Bbls/d)	41,000	39,000	29,000	15,500	8,000

(1) Averages are volume weighted.
(2) If oil prices were to average less than the sold put price, receipts on settlement would be limited to the difference between the floor price and the sold put price.

Based on current futures prices as of November 2, 2016, which average approximately $46 per Bbl for the remainder of 2016, and the fixed-price swaps that we have in place, we currently expect that we will make cash payments for the remainder of the year upon settlement of these contracts, the amount of which is dependent upon fluctuations in future NYMEX prices in relation to the fixed prices of these swaps, which have a weighted average price of $38.80 per Bbl for the remainder of 2016. Changes in commodity prices, expiration of contracts, and new commodity contracts entered into 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, 2016, 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	2016	2015	2016	2015
Lease operating expenses				
Tertiary	$ 61,855	$ 73,749	$ 187,139	$ 238,707
Non-tertiary	44,667	53,868	121,849	162,164
Total normalized lease operating expenses	106,522	127,617	308,988	400,871
Tertiary – special or unusual items	—	(13,715)	—	(13,715)
Total lease operating expenses	$ 106,522	$ 113,902	$ 308,988	$ 387,156
Lease operating expenses per BOE				
Tertiary	$ 18.07	$ 19.63	$ 17.53	$ 20.94
Non-tertiary	19.95	19.15	17.00	18.91
Total normalized lease operating expenses per BOE	18.82	19.43	17.32	20.08
Tertiary – special or unusual items	—	(3.65)	—	(1.20)
Total lease operating expenses per BOE	18.82	17.34	17.32	19.39

Our lease operating costs on an absolute-dollar basis have declined as a result of our cost reduction efforts, as well as general market decreases in the prices of many of the components of these costs. When normalized to exclude a reimbursement for a retroactive utility rate adjustment ($9.6 million) and an insurance reimbursement ($4.1 million) in the 2015 periods, total lease operating expenses decreased $21.1 million (17%) and $91.9 million (23%) on an absolute-dollar basis during the three and nine months ended September 30, 2016, respectively, compared to levels in the same periods in 2015. These reductions were due to cost decreases in most lease operating expense categories, the most significant of which included (1) a decrease in workover costs and repairs as a result of reduced failures through root-cause analysis and fewer well repairs in the nine-month period as more wells are uneconomic to repair based on low commodity prices, (2) lower power costs due to lower usage and rates, (3) lower CO_2 expense resulting from a decrease in CO_2 injection volumes, and (4) lower company labor costs resulting from a reduction in force. The reductions were partially offset by increased repair costs at Thompson Field following the weather-related events of the second quarter of 2016. On a per-BOE basis, our total normalized lease operating expenses for the three and nine months ended September 30, 2016 decreased from the comparative periods in 2015. However, those decreases on a percentage basis were not as large as the absolute-dollar decrease, as our lower production between the periods offset some of the cost reductions. Adjusting for the weather-related impacts at Thompson Field, lease operating expenses per BOE would have been $18.23 and $17.12 for the three and nine months ended September 30, 2016, respectively.

Sequentially, lease operating expenses increased 7% on an absolute-dollar basis and 10% on a per-BOE basis between the second and third quarters of 2016. The increase on an absolute-dollar basis was primarily due to increased repair costs at Thompson Field following the weather-related events of the second quarter of 2016. The sequential quarter increase on a per-BOE basis was further impacted by the decrease in production.

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 2016 and 2015, approximately 57% of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us (our net revenue interest). 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 2016 was approximately $0.35 per Mcf, including taxes paid on CO_2 production but excluding depletion, depreciation and amortization of capital expended at our CO_2 source fields and industrial sources. This per-Mcf CO_2 cost during the third quarter of 2016 was higher than the $0.31 per Mcf during the third quarter of 2015 due primarily to a lower utilization of CO_2, while certain pipeline and processing costs are relatively fixed, but lower than the $0.38 per Mcf comparable measure during the second quarter of 2016 due to higher relative CO_2 volumes in the Gulf Coast region at a lower cost. Including the cost of depletion, 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 $0.47 per Mcf and $0.42 per Mcf during the third quarter of 2016 and 2015, respectively. The increase between periods is primarily the result of the significant reduction of CO_2 production volumes, while certain of our depreciation costs remain fixed. As we anticipate additional industrial-sourced CO_2 volumes from MSPC coming into our CO_2 supply in late 2016 or early 2017, we expect that our per-Mcf cost of CO_2 could trend higher; however, utilizing industrial-sourced CO_2 significantly reduces the future capital we would otherwise have to spend at Jackson Dome and provides a long-term consistent source of CO_2.

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 were $14.5 million for both the three months ended September 30, 2016 and 2015 and $40.6 million and $40.4 million during the nine months ended September 30, 2016 and 2015, respectively.

Taxes Other Than Income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income decreased $5.2 million (20%) and $25.8 million (30%) during the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015, due primarily to a decrease in production taxes resulting from lower oil and natural gas revenues and a decrease in the assessed value of our properties resulting in lower ad valorem taxes during 2016.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE data and employees	2016	2015	2016	2015
Gross cash compensation and administrative costs	$ 60,532	$ 77,879	$ 202,012	$ 257,524
Gross stock-based compensation	7,034	9,621	14,159	29,364
Operator labor and overhead recovery charges	(32,180)	(39,075)	(100,178)	(122,630)
Capitalized exploration and development costs	(10,743)	(15,518)	(34,904)	(47,124)
Net G&A expense	$ 24,643	$ 32,907	$ 81,089	$ 117,134
G&A per BOE:				
Net administrative costs	$ 3.37	$ 3.93	$ 4.04	$ 4.84
Net stock-based compensation	0.98	1.08	0.50	1.03
Net G&A expenses	$ 4.35	$ 5.01	$ 4.54	$ 5.87
Employees as of September 30	1,050	1,354		

Gross cash compensation and administrative costs on an absolute-dollar basis decreased $17.3 million (22%) and $55.5 million (22%) during the three and nine months ended September 30, 2016, compared to those costs in the same periods in 2015, primarily due to lower employee-related costs such as salaries, bonus accruals and long-term incentives. 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 and further reduced our employee headcount in February 2016 through an involuntary workforce reduction, which contributed to an overall headcount reduction of approximately 30% between March 31, 2015 and September 30, 2016. The severance-related payments associated with the 2016 workforce reduction were approximately $9.3 million. The decrease during the nine months ended September 30, 2016 was offset in part by higher severance costs incurred during the first quarter of 2016 compared to severance costs in 2015.

Net G&A expense on a per-BOE basis decreased 13% and 23% during the three and nine months ended September 30, 2016, respectively, compared to levels in the same periods in 2015. The changes were primarily based upon the changes noted in gross cash compensation and administrative costs, partially offset by lower operating and overhead recovery charges, lower capitalized exploration and development costs, and lower production volumes.

Gross stock-based compensation on an absolute-dollar basis decreased $2.6 million (27%) and $15.2 million (52%) during the three and nine months ended September 30, 2016, respectively, compared to levels in the same periods in 2015. The decrease during both periods was primarily due to the reductions in headcount mentioned above, the reduction in previously-recognized stock compensation expense associated with our performance share awards for our executive officers which vested in the first quarter of 2016 or are projected to vest in future periods below target levels, and the postponement of our annual long-term incentive award grants from January in prior years to early July in the current-year period.

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	2016	2015	2016	2015
Cash interest (1)	$ 42,718	$ 44,996	$ 130,511	$ 137,605
Less: interest on 2021 Senior Secured Notes not reflected as interest for financial reporting purposes (1)	(12,533)	—	(19,569)	—
Noncash interest expense	1,468	2,310	11,009	6,810
Less: capitalized interest	(6,875)	(8,081)	(18,944)	(25,228)
Interest expense, net	$ 24,778	$ 39,225	$ 103,007	$ 119,187
Interest expense, net per BOE	$ 4.38	$ 5.97	$ 5.77	$ 5.97
Average debt principal outstanding	$ 2,798,660	$ 3,426,636	$ 3,042,807	$ 3,541,263
Average interest rate (2)	6.1%	5.3%	5.7%	5.2%

(1) Cash interest is presented on an accrual basis, and includes interest on our new 2021 Senior Secured Notes (interest on which is to be paid semiannually May 15 and November 15 of each year, beginning November 15, 2016), which are accounted for as debt and not reflected as interest for financial reporting purposes. See below for further discussion.
(2) Includes commitment fees but excludes debt issue costs and amortization of discount or premium.

As reflected in the table above, cash interest during the three and nine months ended September 30, 2016, decreased when compared to the same periods in 2015 due primarily to repurchasing a total of $181.9 million principal amount of our existing senior subordinated notes at a discount to par value in open-market transactions during the first nine months of 2016. In addition, we entered into privately negotiated exchange transactions during the second quarter of 2016 to exchange $1,057.8 million principal amount of our senior subordinated notes for $614.9 million principal amount of our new 2021 Senior Secured Notes plus 40.7 million shares of Denbury common stock (see *Capital Resources and Liquidity – 2016 Debt Reduction Transactions*). Although these exchange transactions had minimal impact on our cash interest, as more fully described in Note 2, *Long-Term Debt*, to the Unaudited Condensed Consolidated Financial Statements, the exchange transactions were accounted for in accordance with Financial Accounting Standards Board Codification 470-60, *Troubled Debt Restructuring by Debtors*, whereby $254.7 million of future interest on the 2021 Senior Secured Notes has been recorded as debt, which will be reduced as semiannual interest payments are made, with the remaining $22.8 million of future interest to be recognized as interest expense over the term of the 2021 Senior Secured Notes. Therefore, future interest expense reflected in our Unaudited Condensed Consolidated Statements of Operations on the 2021 Senior Secured Notes will be significantly lower than the actual cash interest payment. For the three months ended September 30, 2016, $12.5 million of interest on the 2021 Senior Secured Notes was accounted for as debt, and is therefore not reflected as interest expense in the Unaudited Condensed Consolidated Statements of Operations. Noncash interest expense during the nine months ended September 30, 2016 increased when compared to the same prior year period due to the $5.5 million write-off of debt issuance costs associated with our senior secured bank credit facility following the May 2016 redetermination which reduced our borrowing base and lender commitments and the February 2016 amendment which reduced our lender commitments. Capitalized interest during the three and nine months ended September 30, 2016 decreased $1.2 million (15%) and $6.3 million (25%), respectively, compared to the same periods in 2015, primarily due to a reduction in the number of 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	2016	2015	2016	2015
Depletion and depreciation of oil and natural gas properties	$ 26,669	$ 90,390	$ 112,227	$ 322,440
Depletion and depreciation of CO_2 properties	4,546	5,945	14,590	20,703
Amortization of asset retirement obligations	3,004	2,441	8,881	7,154
Depreciation of pipelines, plants and other property and equipment	20,793	22,630	63,221	69,007
Total DD&A	$ 55,012	$ 121,406	$ 198,919	$ 419,304
DD&A per BOE:				
Oil and natural gas properties	$ 5.24	$ 14.13	$ 6.79	$ 16.51
CO_2 properties, pipelines, plants and other property and equipment	4.48	4.35	4.36	4.49
Total DD&A cost per BOE	$ 9.72	$ 18.48	$ 11.15	$ 21.00
Write-down of oil and natural gas properties	$ 75,521	$ 1,760,600	$ 810,921	$ 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 decreased 68% and 63% on an absolute-dollar basis during the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015. On a per-BOE basis, DD&A of oil and natural gas properties and asset retirement obligations decreased 63% and 59% during the three and nine months ended September 30, 2016, respectively, compared to the same periods in 2015. These decreases were primarily due to a reduction in depletable costs associated with our reserves base resulting from the significant full cost pool ceiling test write-downs recognized during 2015 and the first half of 2016 and an overall reduction in future development costs, partially offset by reductions in proved oil and natural gas reserve quantities. The per-BOE decrease was also partially offset by a decrease in production volumes during the third quarter of 2016 when compared to the 2015 period. Given the additional full cost pool ceiling test write-down recognized during the three months ended September 30, 2016, we currently expect our DD&A rate in the fourth quarter of 2016 to decrease slightly from the third quarter of 2016 rate. 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 may differ from this estimate.

Depletion and depreciation of our CO_2 properties, pipelines, plants and other property and equipment decreased 11% on an absolute-dollar basis and increased 3% on a per-BOE basis during the three months ended September 30, 2016, compared to the same period in 2015. The decrease on an absolute-dollar basis between periods was primarily due to lower depletion associated with our CO_2 properties resulting from a decrease in CO_2 production during the period, while the increase on a per-BOE basis was primarily driven by the decrease in oil and natural gas production volumes between the third quarter of 2015 and 2016.

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. The average first-day-of-the-month NYMEX oil price used in estimating our proved reserves has followed a precipitous and continuing decline in oil prices throughout 2015 and the first nine months of 2016, and the average has declined from $59.21 per Bbl for the third quarter of 2015 to $41.68 per Bbl for the third quarter of 2016. In addition, the average first-day-of-the-month NYMEX natural gas price used in estimating our proved reserves was $3.04 per MMBtu for the third quarter of 2015 and $2.36 per MMBtu for the third quarter of 2016. These third quarter prices represent a decrease of 17% for crude oil and 10% for natural gas prices compared to prices used to calculate the December 31, 2015, full cost ceiling value. These falling prices have led to our recognizing full cost pool ceiling test write-downs of $75.5 million, $479.4 million, and $256.0 million during the three months ended September 30, June 30 and March 31, 2016, respectively, and $1.8 billion, $1.7 billion, and $146.2 million during the three months ended September 30, June 30, and March 31, 2015, respectively. We currently do not expect that we will record a significant write-down in the fourth quarter of 2016 if oil and natural gas prices remain at or near late-October 2016 levels. 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.

2015 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. 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.

Other Expenses

Other expenses totaled $36.2 million during the nine months ended September 30, 2016, primarily comprised of a $27.5 million cash payment to Evolution pursuant to a settlement agreement entered into in June 2016. See Note 7, *Commitments and Contingencies*, to the Unaudited Condensed Consolidated Financial Statements for further discussion.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per-BOE amounts and tax rates	2016	2015	2016	2015
Current income tax expense (benefit)	$ (1,046)	$ 1,184	$ (1,051)	$ 1,063
Deferred income tax benefit	(13,519)	(732,064)	(331,574)	(1,432,572)
Total income tax benefit	$ (14,565)	$ (730,880)	$ (332,625)	$ (1,431,509)
Average income tax benefit per BOE	$ (2.57)	$ (111.25)	$ (18.64)	$ (71.68)
Effective tax rate	37.2%	24.6%	36.0%	29.0%
Total net deferred tax liability	$ 505,689	$ 852,089		

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, 2016, we had $34.5 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 tax valuation allowances of $30.5 million during the second quarter of 2015, $3.1 million during the fourth quarter of 2015, and an additional $0.9 million during the first quarter of 2016, which reduced the carrying value of our deferred tax assets associated with State of Louisiana net operating losses. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

As of September 30, 2016, we had an unrecognized tax benefit of $5.4 million related to an uncertain tax position. The unrecognized tax benefit was recorded during the fourth quarter of 2015 as a direct reduction of the associated deferred tax asset and, if recognized, would not materially affect our annual effective tax rate. The tax benefit from an uncertain tax position will only be recognized if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. We currently do not expect a material change to the uncertain tax position within the next 12 months. Our policy is to recognize penalties and interest related to uncertain tax positions in income tax expense; however, no such amounts were accrued related to the uncertain tax position as of September 30, 2016.

Our income taxes are based on an estimated statutory rate of approximately 38% in 2016 and 2015. Our effective tax rate for the nine months ended September 30, 2016 was slightly lower than our estimated statutory rate, primarily due to the full cost pool ceiling test write-downs recorded. The nine-month period was further impacted by the impact of a tax shortfall on the stock-based compensation deduction (e.g., the compensation expense recognized in the financial statements was greater than the actual compensation realized resulting in a shortfall in the income tax deduction for stock awards that vested during the first quarter) which, prior to the adoption of ASU 2016-09, was recorded as an adjustment to equity. Our effective tax rate for the three and nine 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 third quarter of 2015 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. The deferred income tax benefits during the three and nine months ended September 30, 2016 and 2015, were primarily due to the impact of the write-down of our oil and natural gas properties during the year. In connection with the privately negotiated exchange agreements to exchange a portion of our existing senior subordinated notes for 2021 Senior Secured Notes during the second quarter of 2016, we realized a tax gain due to the concession extended by our note holders. This tax gain was offset by net operating losses and other deferred tax asset attributes.

As of September 30, 2016, we had an estimated $51.1 million of enhanced oil recovery credits to carry forward related to our tertiary operations, $21.6 million of research and development credits, and $41.1 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2016 or future years. The enhanced oil recovery credits and research and development credits do not begin to expire until 2023 and 2031, respectively. We currently do not expect to earn additional enhanced oil recovery credits during 2016.

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	2016	2015	2016	2015
Oil and natural gas revenues	$ 42.38	$ 44.20	$ 37.80	$ 47.81
Receipt (payment) on settlements of commodity derivatives	(1.29)	24.46	6.55	21.70
Lease operating expenses – excluding special items	(18.82)	(19.43)	(17.32)	(20.08)
Lease operating expenses – special items (1)	—	2.09	—	0.69
Production and ad valorem taxes	(3.18)	(3.19)	(2.93)	(3.69)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.99)	(1.91)	(1.89)	(1.75)
Production netback	17.10	46.22	22.21	44.68
CO_2 sales, net of operating and exploration expenses	0.95	1.24	0.93	1.02
General and administrative expenses	(4.35)	(5.01)	(4.54)	(5.87)
Interest expense, net	(4.38)	(5.97)	(5.77)	(5.97)
Other	1.56	0.43	(0.98)	0.67
Changes in assets and liabilities relating to operations	6.15	4.59	(2.92)	0.49
Cash flows from operations	17.03	41.50	8.93	35.02
DD&A	(9.72)	(18.48)	(11.15)	(21.00)
Write-down of oil and natural gas properties	(13.34)	(267.99)	(45.45)	(180.90)
Impairment of goodwill	—	(192.02)	—	(63.17)
Deferred income taxes	2.39	111.43	18.58	71.74
Gain on debt extinguishment	1.38	—	6.45	—
Noncash fair value gains (losses) on commodity derivatives (2)	5.04	(10.45)	(12.14)	(15.38)
Other noncash items	(7.12)	(5.57)	1.69	(1.59)
Net loss	$ (4.34)	$ (341.58)	$ (33.09)	$ (175.28)

(1) Represents 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 2015 periods.

(2) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

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 data and/or 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, financial forecasts, future hydrocarbon prices and timing and degree of any price recovery versus the length or severity of the current commodity price downturn, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to reduce our debt levels, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows, availability of capital, borrowing capacity, future interest rates, availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, or the timing of NGL plant construction or completion or the cost thereof, dates of completion of to-be-constructed industrial plants and the initial date of capture of CO_2 from such plants, timing of CO_2 injections and initial production responses in tertiary flooding projects, acquisition plans and proposals and dispositions, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, helium reserves, potential reserves, barrels or percentages of recoverable original oil in place, the impact of regulatory rulings or changes, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, mark-to-market values, competition, long-term forecasts of production, rates of return, estimated costs, estimates of the range of potential insurance recoveries, changes in costs, future capital expenditures and overall economics, worldwide economic conditions and other variables surrounding our estimated original oil in place, operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "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 our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our 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 and reserve estimates; 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 our other public reports, filings and public statements including, without limitation, the Company's most recent Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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, 2016, we had $260.0 million of debt outstanding on our senior secured 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 light of recent credit downgrades in February 2016, we were required to provide a $41.3 million letter of credit to the lessor, which we provided on March 4, 2016. The letter of credit may be drawn upon in the event Denbury Onshore or Denbury fail to make a payment due under the pipeline financing lease agreement or upon other specified defaults set out in the pipeline financing lease agreement (filed as Exhibit 99.1 to the Form 8-K filed with the SEC on June 5, 2008). The fair values of our senior secured second lien notes and senior subordinated debt is based on quoted market prices. The following table presents the principal cash flows and fair values of our outstanding debt at September 30, 2016:

In thousands	2017	2019	2021	2022	2023	Total	Fair Value
Variable rate debt:							
Senior Secured Bank Credit Facility (weighted average interest rate of 2.8% at September 30, 2016)	$ —	$ 260,000	$ —	$ —	$ —	$ 260,000	$ 260,000
Fixed rate debt:							
9% Senior Secured Second Lien Notes due 2021	—	—	614,919	—	—	614,919	642,590
6⅜% Senior Subordinated Notes due 2021	—	—	215,144	—	—	215,144	154,904
5½% Senior Subordinated Notes due 2022	—	—	—	772,912	—	772,912	544,903
4⅝% Senior Subordinated Notes due 2023	—	—	—	—	622,297	622,297	405,613
Other Subordinated Notes	2,250	—	—	—	—	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. In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2017 using both NYMEX and LLS fixed-price swaps, collars and three-way collars. See also Note 5, *Commodity Derivative Contracts*, and Note 6*, Fair Value Measurements,* 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 commodity 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 senior secured bank credit facility (or affiliates of such lenders). We have included an estimate of nonperformance risk in the fair value measurement of our commodity 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 commodity derivative contracts. This means that any changes in the fair value of these commodity 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, 2016, our commodity derivative contracts were recorded at their fair value, which was a net liability of $73.9 million, a $28.5 million decrease from the $102.4 million net liability recorded at June 30, 2016, and a $216.7 million decrease from the $142.8 million net asset recorded at December 31, 2015. Changes in this value are comprised of the expiration of commodity derivative contracts during the three and nine months ended September 30, 2016, new commodity derivative contracts entered into during 2016 for future periods, and to the changes in oil futures prices between December 31, 2015 and September 30, 2016.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of September 30, 2016, and assuming both a 10% increase and decrease thereon, we would expect to make payments on our crude oil derivative contracts as shown in the following table:

	Receipt / (Payment)	
In thousands	Crude Oil Derivative Contracts	
Based on:		
Futures prices as of September 30, 2016	$	(73,509)
10% increase in prices		(117,136)
10% decrease in prices		(30,311)

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 and natural gas production to which those commodity derivative contracts relate.

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, 2016, 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 2016, 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.

Potential Mississippi Environmental Administrative Proceeding

The Company is currently attempting to conclude negotiations with the Mississippi Department of Environmental Quality ("MDEQ") that began following receipt of a February 2015 notice from the MDEQ related to a discharge of materials at the West Heidelberg Field in Jasper County, Mississippi in the third quarter of 2013. Based upon discussions with the MDEQ during 2016, it is currently anticipated that a settlement related to the discharge providing for a monetary fine as a civil penalty will be reached with the MDEQ in 2016, thus eliminating the need for an administrative proceeding. The Company expects any such fine will not be material to the Company's business or financial condition.

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 2016:

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 2016	10,435	$ 3.26	—	$ 210.1
August 2016	98,409	2.88	—	210.1
September 2016	34,552	3.29	—	210.1
Total	143,396		—	

(1) Stock repurchases during the third quarter of 2016 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, we commenced a common share repurchase program, which has been approved for up to an aggregate of $1.162 billion of Denbury common shares by the Company's Board of Directors. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program, and do not anticipate repurchasing shares of our common stock as long as current commodity pricing and market conditions persist.

Between early October 2011 and September 30, 2016, 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 no repurchases made since October 2015.

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.	Exhibit
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

* Included herewith.

SIGNATURES

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

	DENBURY RESOURCES INC.
November 7, 2016	/s/ Mark C. Allen
	Mark C. Allen Sr. Vice President and Chief Financial Officer
November 7, 2016	/s/ Alan Rhoades
	Alan Rhoades Vice President and Chief Accounting Officer

Denbury Resources Inc.

INDEX TO EXHIBITS

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101	Interactive Data Files.

Exhibit 31(a)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Phil Rykhoek, certify that:

1. I have reviewed this report on Form 10-Q of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

November 7, 2016

/s/ Phil Rykhoek

Phil Rykhoek
Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, certify that:

1. I have reviewed this report on Form 10-Q of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

November 7, 2016

/s/ Mark Allen

Mark C. Allen

Senior Vice President, Chief Financial Officer,
Treasurer, and Assistant Secretary

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-Q for the quarter ended September 30, 2016 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

Dated: November 7, 2016

/s/ Phil Rykhoek
Phil Rykhoek
Chief Executive Officer

Dated: November 7, 2016

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