DENBURY RESOURCES INC
Form 10-Q
August 05, 2016

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

FORM 10-Q
(Mark One)
þ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2016
OR

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

For the transition period from _______ to ________

Commission file number: 001-12935
DENBURY RESOURCES INC.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

Class	Outstanding at July 31, 2016
Common Stock, $.001 par value	398,326,717

Denbury Resources Inc.

Table of Contents

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Denbury Resources Inc.

Unaudited Condensed Consolidated Balance Sheets

(In thousands, except par value and share data)

	June 30, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$2,545	$2,812
Accrued production receivable	120,473	100,413
Trade and other receivables, net	70,700	87,093
Derivative assets	4,699	142,846
Other current assets	14,402	10,005
Total current assets	212,819	343,169
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	10,346,027	10,245,195
Unevaluated properties	909,310	894,948
CO_2 properties	1,186,596	1,187,458
Pipelines and plants	2,294,295	2,293,219
Other property and equipment	399,880	408,194
Less accumulated depletion, depreciation, amortization and impairment	(10,521,061)	(9,653,205)
Net property and equipment	4,615,047	5,375,809
Derivative assets	31	—
Other assets	162,076	166,555
Total assets	$4,989,973	$5,885,533
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$162,334	$253,197
Oil and gas production payable	83,713	87,337
Derivative liabilities	107,105	—
Current maturities of long-term debt	83,762	32,481
Total current liabilities	436,914	373,015
Long-term liabilities		
Long-term debt, net of current portion	2,998,268	3,245,114
Asset retirement obligations	143,981	138,919
Derivative liabilities	67	—
Deferred tax liabilities, net	519,207	852,089
Other liabilities	26,232	27,484
Total long-term liabilities	3,687,755	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; 395,347,234 and 354,541,626 shares issued, respectively	395	355

Paid-in capital in excess of par	2,520,760	2,353,549
Accumulated deficit	(1,608,701)	(1,058,954)
Treasury stock, at cost, 3,745,901 and 3,124,311 shares, respectively	(47,150)	(46,038)
Total stockholders’ equity	865,304	1,248,912
Total liabilities and stockholders’ equity	$4,989,973	$5,885,533

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues and other income				
Oil, natural gas, and related product sales	$246,668	$366,891	$434,471	$664,361
CO_2 sales and transportation fees	6,622	7,152	12,894	14,124
Interest income and other income	1,858	2,651	2,627	5,858
Total revenues and other income	255,148	376,694	449,992	684,343
Expenses				
Lease operating expenses	100,019	132,170	202,466	273,254
Marketing and plant operating expenses	12,999	14,215	26,193	25,900
CO_2 discovery and operating expenses	1,071	945	1,678	1,892
Taxes other than income	19,504	33,555	39,596	60,234
General and administrative expenses	22,545	37,947	56,446	84,227
Interest, net of amounts capitalized of $6,289, $8,738, $12,069, and $17,147, respectively	36,058	39,863	78,229	79,962
Depletion, depreciation, and amortization	66,541	147,940	143,907	297,898
Commodity derivatives expense (income)	98,209	48,926	121,035	(34,150)
Gain on debt extinguishment	(12,278)	—	(107,269)	—
Write-down of oil and natural gas properties	479,400	1,705,800	735,400	1,852,000
Other expenses	34,688	—	36,232	—
Total expenses	858,756	2,161,361	1,333,913	2,641,217
Loss before income taxes	(603,608)	(1,784,667)	(883,921)	(1,956,874)
Income tax benefit	(222,940)	(636,168)	(318,060)	(700,629)
Net loss	$(380,668)	$(1,148,499)	$(565,861)	$(1,256,245)
Net loss per common share				
Basic	$(1.03)	$(3.28)	$(1.58)	$(3.59)
Diluted	$(1.03)	$(3.28)	$(1.58)	$(3.59)
Dividends declared per common share	$—	$0.0625	$—	$0.1250
Weighted average common shares outstanding				
Basic	370,566	350,039	358,901	349,653
Diluted	370,566	350,039	358,901	349,653

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net loss	$(380,668)	$(1,148,499)	$(565,861)	$(1,256,245)
Other comprehensive income, net of income tax:				
Interest rate lock derivative contracts reclassified to income, net of tax of $0, $10, $0, and $21, respectively	—	18	—	35
Total other comprehensive income	—	18	—	35
Comprehensive loss	$(380,668)	$(1,148,481)	$(565,861)	$(1,256,210)

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

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

	Six Months Ended June 30,	
	2016	2015
Cash flows from operating activities		
Net loss	$(565,861)	$(1,256,245)
Adjustments to reconcile net loss to cash flows from operating activities		
Depletion, depreciation, and amortization	143,907	297,898
Write-down of oil and natural gas properties	735,400	1,852,000
Deferred income taxes	(318,055)	(700,508)
Stock-based compensation	4,122	14,967
Commodity derivatives expense (income)	121,035	(34,150)
Receipt on settlements of commodity derivatives	124,253	272,616
Gain on debt extinguishment	(107,269)	—
Debt issuance costs and discounts	14,072	4,501
Other, net	(1,743)	(4,019)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	(20,060)	17,683
Trade and other receivables	17,568	57,865
Other current and long-term assets	(7,974)	(7,770)
Accounts payable and accrued liabilities	(71,830)	(71,892)
Oil and natural gas production payable	(3,624)	(13,217)
Other liabilities	(997)	(3,008)
Net cash provided by operating activities	62,944	426,721
Cash flows from investing activities		
Oil and natural gas capital expenditures	(126,302)	(276,783)
CO_2 capital expenditures	(451)	(15,608)
Pipelines and plants capital expenditures	(1,965)	(20,349)
Other	1,198	(23,772)
Net cash used in investing activities	(127,520)	(336,512)
Cash flows from financing activities		
Bank repayments	(994,000)	(1,007,000)
Bank borrowings	1,139,000	962,000
Repurchases of senior subordinated notes	(55,521)	—
Pipeline financing and capital lease debt repayments	(14,336)	(17,122)
Cash dividends paid	(413)	(43,528)
Other	(10,421)	(3,299)
Net cash provided by (used in) financing activities	64,309	(108,949)
Net decrease in cash and cash equivalents	(267)	(18,740)
Cash and cash equivalents at beginning of period	2,812	23,153
Cash and cash equivalents at end of period	$2,545	$4,413

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents
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 employee stock compensation plans	44,346	—	—	—	—	—	—
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	—	—	7,125	—	—	—	7,125
Tax withholding – stock compensation	—	—	—	—	621,590	(1,112)	(1,112)
Dividends adjustments	—	—	—	42	—	—	42
Net loss	—	—	—	(565,861)	—	—	(565,861)
Balance – June 30, 2016	395,347,234	$ 395	$2,520,760	$(1,608,701)	3,745,901	$(47,150)	$865,304

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

Note 1. Basis of Presentation

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is 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 June 30, 2016, our consolidated results of operations for the three and six months ended June 30, 2016 and 2015, our consolidated cash flows for the six months ended June 30, 2016 and 2015, and our consolidated statement of changes in stockholders' equity for the six months ended June 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 options, stock appreciation rights ("SARs"), and nonvested performance-based equity awards. For the three and six months ended June 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 June 30,		Six Months Ended June 30,	
In thousands	2016	2015	2016	2015
Basic weighted average common shares outstanding	370,566	350,039	358,901	349,653
Potentially dilutive securities				
Restricted stock, stock options, SARs and performance-based equity awards	—	—	—	—
Diluted weighted average common shares outstanding	370,566	350,039	358,901	349,653

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 June 30,		Six Months Ended June 30,	
In thousands	2016	2015	2016	2015
Stock options and SARs	6,265	9,949	6,839	10,228
Restricted stock and performance-based equity awards	4,374	2,241	4,491	2,595

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.

As a result of the precipitous and continuing decline in NYMEX oil prices since the fourth quarter of 2014, the average first-day-of-the-month NYMEX oil price used in estimating our proved reserves has fallen throughout 2015 and the first half of 2016, from $71.68 per Bbl for the second quarter of 2015 to $43.12 per Bbl for the second quarter of 2016. In addition, the average first-day-of-the-month NYMEX natural gas price used in estimating our proved reserves was $3.38 per MMBtu for the second quarter of 2015 and $2.33 per MMBtu for the second quarter of 2016.

These falling prices have led to our recognizing full cost pool ceiling test write-downs of $479.4 million and $256.0 million during the three months ended June 30 and March 31, 2016, respectively, and $1.7 billion and $146.2 million during the three months ended June 30 and March 31, 2015, respectively.

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.

Table of Contents
Denbury Resources Inc.
Notes to Unaudited Condensed 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.

Note 2. Long-Term Debt

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

In thousands	June 30, 2016	December 31, 2015
Senior Secured Bank Credit Agreement	$320,000	$175,000
9% Senior Secured Second Lien Notes due 2021	614,919	—
6 % Senior Subordinated Notes due 2021	220,939	400,000
5½% Senior Subordinated Notes due 2022	796,712	1,250,000
4 % Senior Subordinated Notes due 2023	622,297	1,200,000
Other Subordinated Notes, including premium of $5 and $7, respectively	2,255	2,257
Pipeline financings	207,448	211,766
Capital lease obligations	60,124	71,324
Total principal balance	2,844,694	3,310,347
Future interest payable on 9% Senior Secured Second Lien Notes due 2021 (1)	254,660	—
Issuance costs on senior subordinated notes	(17,324)	(32,752)
Total debt, net of debt issuance costs on senior subordinated notes	3,082,030	3,277,595
Less: current maturities of long-term debt (1)	(83,762)	(32,481)
Long-term debt and capital lease obligations	$2,998,268	$3,245,114

(1) Future interest payable on our 9% Senior Secured Second Lien Notes due 2021 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 June 30, 2016 include $51.0 million of future interest payable related to this balance 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 connection with our May 2016 borrowing base redetermination, our borrowing base and lender commitments were reduced to $1.05 billion, with the next such redetermination scheduled for November 2016.

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 (currently, 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 June 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 $169.5 million available as of June 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 semi-annual scheduled redeterminations of the borrowing base in May and November of each year. As of June 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 June 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 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. The exchanged notes consisted of $175.1 million principal amount of our 6 % 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 4 % Senior Subordinated Notes due 2023 (“2023 Notes”).

In accordance with FASB ASC 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 has been recorded as debt, which will be reduced as semi-annual 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 on the 2021 Senior Secured Notes will be significantly lower than the actual cash interest payments. In addition, we recognized a gain of $12.3 million as a result of this debt exchange, 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 semi-annually 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 February and March 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. In connection with these transactions, we recognized a $95.0 million gain on extinguishment, net of unamortized debt issuance costs written off. During July 2016, we repurchased an additional $19.6 million of senior subordinated notes in open-market transactions, consisting of $3.3 million principal amount of our 2021 Notes and $16.3 million principal amount of our 2022 Notes, for a total purchase price of $14.2 million, excluding accrued interest. As of August 3, 2016, under the Bank Credit Agreement, an additional $155.3 million may be spent on senior subordinated notes repurchases or other redemptions.

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 June 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 June 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 June 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. This tax gain was offset by net operating losses and other deferred tax asset attributes.

Note 4. Stockholders’ Equity

Dividends

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 $43.5 million paid to stockholders during the six months ended June 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 June 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.

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

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

Months	Index Price	Volume (Barrels per day)	Contract Prices ($/Bbl)				
			Range [1]	Weighted Average Price			
				Swap	Sold Put	Floor	Ceiling
Oil Contracts:							
2016 Fixed-Price Swaps							
July – Sept	NYMEX	18,500	$36.25–45.08	$38.96	$—	$—	$—
July – Sept	LLS	7,000	37.24–42.15	39.61	—	—	—
Oct – Dec	NYMEX	26,000	36.25–45.40	38.70	—	—	—
Oct – Dec	LLS	7,000	37.24–41.00	39.16	—	—	—
2016 Collars							
July – Sept	NYMEX	4,500	$55.00–72.65	$—	$—	$55.00	$71.22
July – Sept	NYMEX	4,000	40.00–51.80	—	—	40.00	51.40
July – Sept	LLS	3,000	58.00–74.30	—	—	58.00	73.85
July – Sept	LLS	5,000	40.00–54.25	—	—	40.00	53.74
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	6,500	$40.00–70.25	$—	$30.00	$40.00	$69.74
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 June 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 $80 thousand in the fair value of these instruments as of June 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.

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

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

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
June 30, 2016				
Assets				
Oil derivative contracts – current	$—	$2,619	$ 2,080	$4,699
Oil derivative contracts – long-term	—	31	—	31
Total Assets	$—	$2,650	$ 2,080	$4,730
Liabilities				
Oil derivative contracts – current	$—	$105,310	$ 1,795	$107,105
Oil derivative contracts – long-term	—	22	45	67
Total Liabilities	$—	$105,332	$ 1,840	$107,172
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 six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2016	2015	2016	2015
Fair value of Level 3 instruments, beginning of period	$23,040	$165,015	$52,834	$188,446
Fair value adjustments on commodity derivatives	(4,818)	(7,302)	(4,536)	17,783
Receipts on settlements of commodity derivatives	(17,982)	(45,355)	(48,058)	(93,871)
Fair value of Level 3 instruments, end of period	$240	$112,358	$240	$112,358
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	$(3,857)	$(4,325)	$(3,870)	$14,142

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 6/30/2016 (in thousands)	Valuation Technique	Unobservable Input	Volatility Range
Oil derivative contracts	$ 240	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after June 30, 2016	21.1% - 41.4%

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 June 30, 2016 and December 31, 2015, excluding pipeline financing and capital lease obligations, was $2,033.6 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 the second half of 2016. 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.

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

On June 24, 2016, we entered into a settlement agreement with Evolution Petroleum Corporation (together with its subsidiaries, “Evolution”) resolving all outstanding disputes and claims the parties had or may have had against each other, including pending litigation claims, involving the Delhi Field in northeastern Louisiana.

In addition to clarifying certain aspects of the parties’ ongoing relationship as joint interest holders in the Delhi Field, the settlement resolves (1) claims by Denbury related to the purchase of our original Delhi Field interest from Evolution; (2) disputes regarding the occurrence, determination, timing, nature and terms of “payout” and Evolution’s related reversionary interest in the Delhi Field; and (3) any claims by Evolution in connection with the June 2013 incident at the Delhi Field (the “June 2013 Incident”).

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; 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.

Note 8. Additional Balance Sheet Details

Accounts Payable and Accrued Liabilities

In thousands	June 30, 2016	December 31, 2015
Accrued interest	$29,182	$48,908
Accrued lease operating expenses	28,482	37,549
Accounts payable	24,675	30,477
Taxes payable	19,342	32,438
Accrued compensation	16,423	46,780
Accrued exploration and development costs	4,906	20,892
Other	39,324	36,153
Total	$162,334	$253,197

Note 9. Subsequent Event

Employee Equity Award Grant

The Compensation Committee of our Board of Directors granted customary long-term equity incentive awards to our employees under the 2004 Omnibus Stock and Incentive Plan on July 8, 2016 covering 6,851,346 shares of restricted stock. The closing price of Denbury’s common stock on July 8, 2016 was $3.22 per share. The awards generally vest one-third per year over a three-year period.

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 prices have declined to less than $27 per Bbl in January 2016, the lowest level in over 13 years, and an average of approximately $46 per Bbl in the second 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 half of 2016.

	Three Months Ended									
Average realized prices	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
Oil price per Bbl	$97.69	$100.04	$94.78	$ 70.80	$46.02	$56.92	$45.74	$ 40.41	$30.71	$43.38

Although average second quarter oil prices 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, and our second quarter results demonstrate our continued progress in that regard. 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 recent weather-related downtime at Conroe and Thompson fields and planned asset sales. This decline rate is even lower if we exclude wells that we anticipate will be shut in for economic reasons. Lastly, we have hedged approximately two-thirds of our estimated oil production through the first quarter of 2017 and approximately half of our estimated oil production in the second quarter of 2017 in order to cover our current level of cash costs and to help mitigate any future price declines or sustained low oil prices.

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. Over the past year, we have reduced our overall CO_2 injection volumes by 40% and our lease operating expenses by 24% when comparing the second quarters of 2015 and 2016. 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 and provide us with liquidity for the foreseeable future.

2016 Debt Reduction Transactions. During 2016, we have completed a series of privately negotiated exchange agreements and open-market transactions, resulting in a net reduction of our debt principal balance of approximately $545 million. 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 February and March 2016, we repurchased $152.3 million of our existing senior subordinated notes for $55.5 million in open-market transactions, for a net reduction of $96.7 million of our debt principal. During July 2016, we repurchased additional existing senior subordinated notes in open-market transactions, for an additional net reduction of $5.4 million of our debt principal. See Capital Resources and Liquidity – 2016 Debt Reduction Transactions for further discussion.

2016 Divestiture of Non-Core Assets. On June 20, 2016, we entered into a purchase and sale agreement to sell our remaining non-core assets in the Williston Basin of North Dakota and Montana (the “Williston Assets”) for $58 million (before final closing adjustments) with an effective date of April 1, 2016. We expect to close on this transaction during the third quarter of 2016. Production from the Williston Assets averaged 1,267 BOE/d and 1,315 BOE/d during the three and six months ended June 30, 2016, respectively.

Operating Highlights. Our financial results continue to be impacted by the decrease in realized oil prices as highlighted above, which decreased from an average of $56.92 per Bbl in the second quarter of 2015 to $43.38 in the second quarter of 2016, partially offset by significant reductions in nearly all of our expense categories. During the second quarter of 2016, we recognized a net loss of $380.7 million, or $1.03 per diluted common share, compared to a net loss of $1.1 billion, or $3.28 per diluted common share, during the second quarter of 2015. The change in net loss between the second quarter of 2015 and 2016 was primarily due to the much smaller full cost pool ceiling test write-down of our oil and natural gas properties, which totaled $479.4 million ($299.4 million net of tax) in the second quarter of 2016, compared to $1.7 billion ($1.1 billion net of tax) in the second quarter of 2015 (see Write-Down of Oil and Natural Gas Properties below). Other significant changes between the second quarter of 2015 and 2016 included a $120.2 million (33%) decline in our oil and natural gas revenues between the periods due to lower oil prices and production volumes, a $49.3 million increase in commodity derivatives expense, and $34.7 million of other expenses in the second quarter of 2016, offset in part by a $81.4 million (55%) decrease in depletion, depreciation, and amortization, a $32.2 million (24%) reduction in lease operating expense, a $15.4 million (41%) decrease in general and administrative expenses, a $14.1 million (42%) decrease in taxes other than income, and a $12.3 million gain on debt extinguishment in the second quarter of 2016. The $49.3 million increase in commodity derivatives expense between the two periods was due to a $72.1 million comparative reduction in receipts from settlements of derivative contracts during the 2016 period, partially offset by a $22.8 million decrease in loss associated with noncash fair value commodity adjustments.

We generated $60.9 million of cash flows from operating activities in the second quarter of 2016, an increase of $58.9 million from the $2.0 million generated in the first quarter of 2016. The sequential increase in cash flows from operations was due primarily to quarter-to-quarter increases in oil prices, as well as reductions in general and administrative expenses, and a $22.8 million decrease in working capital outflows, partially offset by a decline in derivative settlements and the $27.5 million cash outflow related to our legal settlement with Evolution Petroleum Corporation (“Evolution”). When compared to prior year, cash flows from operating activities decreased $228.1 million from $289.0 million in the prior-year second quarter, due primarily to lower oil prices and production volumes, which caused a decrease in oil revenues, a decline in derivative settlements, and the Evolution settlement, partially offset by reductions in lease operating expenses, general and administrative expenses, taxes other than income, and changes in working capital items.

During the second quarter of 2016, our oil and natural gas production, which was 96% oil, averaged 64,506 BOE/d, compared to an average of 73,716 BOE/d produced during the second quarter of 2015 and 69,351 BOE/d during the first quarter of 2016. The year-over-year and sequential quarterly declines were primarily due to weather-related shut-in production, production shut in due to economics, a higher net profits interest of a third party and downtime resulting from power failures and repair work at Cedar Creek Anticline (“CCA”), and natural production declines based on our lower capital spending level.

These production decreases were partially offset by increases in production due to continued CO_2 enhanced oil recovery response at Bell Creek Field in the Rocky Mountain region. As a result of the items discussed above and the planned sale of our non-core Williston Assets, which had average production of approximately 1,300 BOE/d for the first half of this year, we now expect our full-year 2016 production to range between 64,000 BOE/d and 66,000 BOE/d, as compared to our previous estimates of between 64,000 and 68,000 BOE/d, with our production for the remainder of the year being relatively flat with our second quarter production after adjusting for the planned asset sale. See Results of Operations – Production for further discussion.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, was $43.38 per Bbl during the second quarter of 2016, a decrease of 24% compared to $56.92 per Bbl realized during the second quarter of 2015 and an increase of 41% compared to $30.71per Bbl realized during the first quarter of 2016. The oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) was $2.18 per Bbl below NYMEX prices in the second quarter of 2016, compared to a negative 0.89 per-Bbl NYMEX differential in the second quarter of 2015 and a negative $3.02 per-Bbl NYMEX differential in the first quarter of 2016. The weakening in our oil price differential in comparison to its level in the second 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 make continued reductions in our lease operating expenses, with total lease operating expenses of $100 million during the second quarter of 2016, a 24% reduction from the prior-year second quarter. Lease operating expenses per BOE during the second quarter of 2016 were $17.04, as compared to $19.70 in the second quarter of 2015, with decreases realized in most categories of lease operating expenses. On a sequential quarter basis, lease operating expenses per BOE increased 5% from the first quarter of 2016 primarily due to our 7% decline in production and higher workover expenses, while general and administrative expenses per BOE decreased 28% from the first quarter of 2016 due to lower employee-related costs such as salaries and payroll taxes following the involuntary workforce reduction in the first quarter of 2016. General and administrative expenses in the first quarter of 2016 also included severance-related payments of approximately $9.3 million.

Write-Down of Oil and Natural Gas Properties. Due to a continued decline in the rolling first-day-of-the-month average oil and natural gas price for the preceding 12-month periods in 2015 and 2016, we recognized full cost pool ceiling test write-downs of $479.4 million and $1.7 billion during the three months ended June 30, 2016 and June 30, 2015, respectively. See Note 1, Basis of Presentation – Write-Down of Oil and Natural Gas Properties, to the Unaudited Condensed Consolidated Financial Statements, and Results of Operations – Write-Down of Oil and Natural Gas Properties for additional information regarding the ceiling test.

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 will be 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 $289.0 million during the three months ended June 30, 2015, to $60.9 million during the three months ended June 30, 2016.

The preservation of cash and liquidity remains a significant priority until oil prices improve. We have taken and will continue to take 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 to address potential covenant compliance issues if oil prices return to levels comparable to those realized in the first quarter of 2016. As of June 30, 2016, we had $320.0 million drawn on our $1.05 billion senior secured bank credit facility, leaving us $670.7 million of current liquidity after consideration of $59.3 million of outstanding letters of credit. This liquidity, coupled with our other cost saving and liquidity measures, should be sufficient to supplement our capital or operating cash outflows as needed until oil prices improve, which we believe will be in the next twelve to eighteen months.

To protect our liquidity, we have entered into oil swaps and collars for the second half of 2016 and the first three quarters of 2017, such that we now have hedged approximately two-thirds of our estimated oil production through the first quarter of 2017 and approximately half of our estimated oil production in the second quarter of 2017. While a portion of these derivatives 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 $30’s in the second quarter of 2016, including corporate overhead and interest, thereby minimizing the amount that would be required for day-to-day operations from our bank line.

Since we do not expect oil prices to recover to recent historical highs, 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 with a net debt reduction of $545 million through August 3, 2016, which lowers the urgency for other reductions, but we would prefer to reduce our debt further. Our subordinated debt is still trading below par, which provides further opportunities to acquire the debt at a discount, although such purchases are not as advantageous as they were earlier in 2016 and we must also be conscious of our liquidity in case oil prices were to remain lower or drop below current levels.

We plan to continue reviewing our options to reduce such debt which may include purchases of our subordinated debt in the open market, cash tenders for such debt or debt exchanges, and longer-term, potentially issuances of equity, asset sales and other cash-generating activities. We may utilize a portion of our bank line for such repurchases and may also consider other forms of capital such as second lien notes or other senior notes. Such activities will depend on the availability and cost of such capital and relevant market conditions, including oil prices and market trading levels of our subordinated notes. Any purchases of debt may be made in the open market, in privately negotiated transactions, through tender or exchange offers or otherwise.

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”). As of June 30, 2016, we had $320.0 million of debt outstanding (based on a $1.05 billion borrowing base and commitment level from our banks) and $59.3 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 (currently, 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 June 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 $169.5 million available as of June 30, 2016.

For these financial performance covenant calculations as of June 30, 2016, our ratio of consolidated senior secured debt to consolidated EBITDAX was 0.45 to 1.0, our ratio of consolidated EBITDAX to consolidated interest charges was 4.01 to 1.0, and our current ratio was 3.57. Based upon our currently forecasted levels of production and costs, hedges in place as of August 3, 2016, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our bank covenants during 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, resulting in a net reduction of our debt principal balance of approximately $545 million. During May 2016, we entered into privately negotiated exchange agreements to exchange $175.1 million principal amount of our 6 % 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 4 % 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. The repurchases were made at prices ranging from approximately 25% to 45% of the principal amount of the individual senior subordinated notes. In connection with these transactions, we recognized a $95.0 million gain on debt extinguishment, net of unamortized debt issuance costs written off. During July 2016, we repurchased an additional $19.6 million of senior subordinated notes in open-market transactions, consisting of $3.3 million principal amount of our 2021 Notes and $16.3 million principal amount of our 2022 Notes in open-market transactions for a total purchase price of $14.2 million, excluding accrued interest. We currently estimate combined cash interest savings of approximately $7 million related to these repurchases and the exchange transactions. Our bank agreement limits the cash amount that we may spend on open-market repurchases of our senior subordinated notes to $225 million, and as of August 3, 2016, we have $155.3 million of remaining capacity to spend on 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. However, we could potentially adjust this budget higher or lower based on changes in estimated levels of cash flow. This combined 2016 capital budget amount, excluding capitalized interest and acquisitions, is comprised of the following:

- $100 million allocated for tertiary oil field expenditures;
- $35 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $10 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 June 30, 2016, we had ample availability on our senior secured bank credit facility to cover any foreseeable cash flow shortfall. If prices were to decrease further or changes in operating results were to cause us to have a reduction in anticipated 2016 cash flows below our currently forecasted operating cash flows, we could potentially make minor additional reductions in our capital expenditures, as further significant reductions in our capital spending are limited to some degree by existing prior commitments and capitalized items. If we further reduce our capital spending due to lower cash flows, any sizeable reduction could further lower our anticipated production levels in future years.

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

	Six Months Ended June 30,	
In thousands	2016	2015
Capital expenditures by project		
Tertiary oil fields	$63,898	$96,594
Non-tertiary fields	10,776	52,579
Capitalized internal costs [(1)]	25,787	33,911
Oil and natural gas capital expenditures	100,461	183,084
CO_2 pipelines	135	6,296
CO_2 sources	—	10,482
Other	17	44
Capital expenditures, before acquisitions and capitalized interest	100,613	199,906
Acquisitions of oil and natural gas properties	904	21,959
Capital expenditures, before capitalized interest	101,517	221,865
Capitalized interest	12,069	17,147
Capital expenditures, total	$113,586	$239,012

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

For the six months ended June 30, 2016, our capital expenditures and property acquisitions were funded with cash flows from operations and borrowings on our senior secured bank credit facility, with these incremental borrowings primarily being required to cover working capital outflows during the period. For the six months ended June 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 the second half of 2016. 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.

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

Operating Results Table

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-share and unit data	2016	2015	2016	2015
Operating results				
Net loss [1]	$(380,668)	$(1,148,499)	$(565,861)	$(1,256,245)
Net loss per common share – basic [1]	(1.03)	(3.28)	(1.58)	(3.59)
Net loss per common share – diluted [1]	(1.03)	(3.28)	(1.58)	(3.59)
Dividends declared per common share	—	0.0625	—	0.1250
Net cash provided by operating activities	60,915	288,957	62,944	426,721
Average daily production volumes				
Bbls/d	61,952	69,837	64,045	70,199
Mcf/d	15,328	23,273	17,299	23,014
BOE/d [2]	64,506	73,716	66,929	74,034
Operating revenues				
Oil sales	$244,572	$361,732	$429,388	$654,002
Natural gas sales	2,096	5,159	5,083	10,359
Total oil and natural gas sales	$246,668	$366,891	$434,471	$664,361
Commodity derivative contracts [3]				
Receipt on settlements of commodity derivatives	$52,026	$124,151	$124,253	$272,616
Noncash fair value adjustments on commodity derivatives [4]	(150,235)	(173,077)	(245,288)	(238,466)
Commodity derivatives income (expense)	$(98,209)	$(48,926)	$(121,035)	$34,150
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$43.38	$56.92	$36.84	$51.47
Natural gas price per Mcf	1.50	2.44	1.61	2.49
Unit prices – including impact of derivative settlements [3]				
Oil price per Bbl	$52.61	$76.30	$47.50	$72.79
Natural gas price per Mcf	1.50	2.89	1.61	2.90
Oil and natural gas operating expenses				
Lease operating expenses	$100,019	$132,170	$202,466	$273,254
Marketing expenses, net of third-party purchases, and plant operating expenses	10,890	12,494	22,482	22,337
Production and ad valorem taxes	17,040	29,718	34,218	52,617
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$42.02	$54.69	$35.67	$49.58
Lease operating expenses	17.04	19.70	16.62	20.39
Marketing expenses, net of third-party purchases, and plant operating expenses	1.85	1.86	1.84	1.66
Production and ad valorem taxes	2.90	4.43	2.81	3.93
CO_2 sources – revenues and expenses				
CO_2 sales and transportation fees	$6,622	$7,152	$12,894	$14,124
CO_2 discovery and operating expenses	(1,071)	(945)	(1,678)	(1,892)
CO_2 revenue and expenses, net	$5,551	$6,207	$11,216	$12,232

(1) Includes full cost pool ceiling test write-downs of $479.4 million and $735.4 million for the three and six months ended June 30, 2016, respectively, and $1.7 billion and $1.9 billion for the three and six months ended June 30, 2015, respectively.

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

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

(4) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure and is different from “Commodity derivatives expense (income)” in the Unaudited Condensed Consolidated Statements of Operations in that the noncash fair value adjustments on commodity derivatives 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 receipts on settlements of $52.0 million and $124.3 million for the three and six months ended June 30, 2016, compared to receipts on settlements of $124.2 million and $272.6 million for the three and six months ended June 30, 2015. We believe that noncash fair value adjustments on commodity derivatives is a useful supplemental disclosure to “Commodity derivatives expense (income)” in order to differentiate noncash fair market value adjustments from 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 adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for “Commodity derivatives expense (income)” in the Unaudited Condensed Consolidated Statements of Operations.

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 and second 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
Tertiary oil production						
Gulf Coast region						
Mature properties (1)	10,801	11,170	10,946	10,403	9,666	9,415
Delhi	3,551	3,623	3,676	3,898	3,971	3,996
Hastings	4,694	5,350	5,114	5,082	5,068	4,972
Heidelberg	6,027	5,885	5,600	5,635	5,346	5,246
Oyster Bayou	5,861	5,936	5,962	5,831	5,494	5,088
Tinsley	8,928	8,740	7,311	7,522	7,899	7,335
Total Gulf Coast region	39,862	40,704	38,609	38,371	37,444	36,052
Rocky Mountain region						
Bell Creek	1,965	1,880	2,225	2,806	3,020	3,160
Total Rocky Mountain region	1,965	1,880	2,225	2,806	3,020	3,160
Total tertiary oil production	41,827	42,584	40,834	41,177	40,464	39,212
Non-tertiary oil and gas production						
Gulf Coast region						
Mississippi	1,761	1,400	1,592	1,800	978	1,280
Texas	6,490	6,304	6,508	6,470	6,148	4,104
Other	1,006	906	846	800	549	456
Total Gulf Coast region	9,257	8,610	8,946	9,070	7,675	5,840
Rocky Mountain region						
Cedar Creek Anticline	18,522	18,089	17,515	17,875	17,778	16,325
Other	4,750	4,433	4,115	3,880	3,434	3,129
Total Rocky Mountain region	23,272	22,522	21,630	21,755	21,212	19,454
Total non-tertiary production	32,529	31,132	30,576	30,825	28,887	25,294
Total production	74,356	73,716	71,410	72,002	69,351	64,506
Pending property sales						
Williston Assets (2)	(1,643)	(1,561)	(1,522)	(1,473)	(1,364)	(1,267)
Continuing production	72,713	72,155	69,888	70,529	67,987	63,239

(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, expected to close in the third quarter of 2016.

Total Production

Total production during the second quarter of 2016 averaged 64,506 BOE/d, a decrease of 4,845 BOE/d (7%) compared to first quarter of 2016 production levels and of 9,210 BOE/d (12%) compared to second quarter of 2015 production levels. The year-over-year and sequential quarterly declines were primarily due to weather-related shut-in production, production shut in due to economics, a higher net profits interest of a third party and downtime resulting from power failures and repair work at CCA, and natural production declines based on our lower capital spending level. In mid-April 2016, a series of strong thunderstorms in the Houston area affected two Denbury fields, causing damage to a primary tank battery in Conroe Field and flooding at Thompson Field. Most of the impacted production at Conroe Field was back online in late-June 2016, with the remainder expected to be restored throughout the last half of 2016. As we were beginning to return Thompson Field to production in late-May 2016, additional record rainfall in the area caused us to again shut in production due to further flooding. We are currently working to restore full production in the field, and expect to have most of this shut-in production back online by the end of August. These series of storms impacted quarterly production by approximately 1,450 BOE/d, which caused approximately one-third of the 7% sequential quarterly production decline.

Quarterly production was further impacted by production shut-in attributable to uneconomic wells, resulting in a decrease to quarterly production of approximately 2,750 BOE/d, representing an incremental decrease of approximately 300 BOE/d when compared to the first quarter of 2016 and approximately 2,100 BOE/d when compared to the second quarter of 2015. Although the quarterly production impact for these uneconomic wells was higher than the previous quarter, near the end of the second quarter, we began to restore some of these wells to production as oil prices were trending higher. As such, as of quarter end, we estimate that approximately 2,600 BOE/d of production remained shut in as of June 30, 2016 attributable to uneconomic wells, a reduction of approximately 200 BOE/d from March 31, 2016 levels.

These decreases were partially offset by increases in production due to continued CO_2 enhanced oil recovery response at Bell Creek Field in the Rocky Mountain region. We currently estimate our production for the remainder of the year will be relatively flat with our second quarter production after adjusting for the planned sale of our non-core Williston Assets, which had average production of approximately 1,300 BOE/d for the first half of this year. Our production during the three and six months ended June 30, 2016 was 96% oil, consistent with oil production of 95% during the three and six months ended June 30, 2015.

Tertiary Production

Oil production from our tertiary operations during the second quarter of 2016 decreased 1,252 Bbls/d (3%) sequentially and by 3,372 Bbls/d (8%) compared to that in the same period in 2015. These decreases were primarily due to seasonal facility processing constraints at Tinsley Field as the impact of warmer temperatures restricted CO_2 injection and recycling, and at Oyster Bayou Field, which experienced downtime due to repairs and workovers. Although production from these fields could have moderate increases in the third quarter of 2016 as production comes back online, both of these fields are believed to have peaked and therefore are expected to generally decline in the future. These declines were partially offset by increased production due to continued CO_2 enhanced oil recovery response at Bell Creek Field in the Rocky Mountain region.

Non-Tertiary Production

Production from our non-tertiary operations averaged 25,294 BOE/d during the second quarter of 2016, a decrease of 3,593 BOE/d (12%) sequentially and a decrease of 5,838 BOE/d (19%) compared to the second quarter of 2015 levels. The production declines include weather-related downtime at Conroe and Thompson fields, as noted above, and production that we estimated to be attributable to wells shut in as uneconomic to either produce or repair due to commodity prices. In addition, the sequential and year-over-year changes include (1) decreases at CCA due to the net profits interest of a third party, whereby improved operational efficiencies and margins have resulted in increased profitability and thus, lower reported production quantities net to Denbury of approximately 500 BOE/d when compared to the first quarter of 2016, (2) downtime at CCA resulting from weather-related power failures and repair work, resulting in a sequential decrease of approximately 150 BOE/d, and (3) natural production declines at our non-tertiary properties in the Rocky Mountain and Gulf Coast regions.

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

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and six months ended June 30, 2016 decreased 33% and 35%, 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:

In thousands	Three Months Ended June 30, 2016 vs. 2015 Decrease in Revenues	Three Months Ended June 30, 2016 vs. 2015 Percentage Decrease in Revenues	Six Months Ended June 30, 2016 vs. 2015 Decrease in Revenues	Six Months Ended June 30, 2016 vs. 2015 Percentage Decrease in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$(45,836)	(12)%	$(60,445)	(9)%
Decrease in commodity prices	(74,387)	(21)%	(169,445)	(26)%
Total decrease in oil and natural gas revenues	$(120,223)	(33)%	$(229,890)	(35)%

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, and six months ended June 30, 2016 and 2015:

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Average net realized prices:						
Oil price per Bbl	$30.71	$46.02	$43.38	$56.92	$36.84	$51.47
Natural gas price per Mcf	1.70	2.54	1.50	2.44	1.61	2.49
Price per BOE	29.76	44.45	42.02	54.69	35.67	49.58
Average NYMEX differentials:						
Oil per Bbl	$(3.02)	$(2.81)	$(2.18)	$(0.89)	$(2.81)	$(1.87)
Natural gas per Mcf	(0.29)	(0.28)	(0.73)	(0.30)	(0.50)	(0.29)

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, decreased 24% during the second quarter of 2016 from the average price received during the second quarter of 2015 and increased 41% compared to the average price received during the first quarter of 2016. Company-wide average oil price differentials in the second quarter of 2016 were $2.18 per Bbl below NYMEX, compared to an average differential of $0.89 per Bbl below NYMEX in the second quarter of 2015 and $3.02 per Bbl below NYMEX in the first 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 $1.22 per Bbl and a positive $1.86 per Bbl during the three months ended June 30, 2016 and 2015, respectively, and a negative $1.95 per Bbl during the three months ended March 31, 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 \$2.04 per Bbl in the second quarter of 2016, down from a positive \$6.29 per Bbl in the second quarter of 2015 and up from a positive \$1.60 per Bbl in the first quarter of 2016. During the second 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 $3.98 per Bbl and $6.48 per Bbl below NYMEX during the three months ended June 30, 2016 and 2015, respectively, and $5.04 per Bbl below NYMEX during the three months ended March 31, 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 six months ended June 30, 2016 and 2015:

	Three Months Ended June 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	$52,026	$123,183	$—	$968	$52,026	$124,151
Noncash fair value adjustments on commodity derivatives (1)	(150,235)	(172,022)	—	(1,055)	(150,235)	(173,077)
Total expense	$(98,209)	$(48,839)	$—	$(87)	$(98,209)	$(48,926)

	Six Months Ended June 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	$124,253	$270,899	$—	$1,717	$124,253	$272,616
Noncash fair value adjustments on commodity derivatives (1)	(245,288)	(237,144)	—	(1,322)	(245,288)	(238,466)
Total income (expense)	$(121,035)	$33,755	$—	$395	$(121,035)	$34,150

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

In order to protect our liquidity and provide price certainty to a portion of our oil production, we have hedged approximately two-thirds of our estimated oil production through the first quarter of 2017 and approximately half of our estimated oil production in the second quarter of 2017 using both NYMEX and LLS fixed-price swaps and collars. Based on current futures prices as of August 3, 2016, which average approximately $42 per Bbl for the remainder of 2016, and the fixed-price swaps that we have in place, we currently expect that we will begin making payments in the third quarter of 2016 (and continue to do so 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 $38.95 per Bbl for the second half 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 June 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		Six Months Ended	
	June 30,		June 30,	
In thousands, except per-BOE data	2016	2015	2016	2015
Lease operating expense				
Tertiary	$63,096	$79,499	$125,284	$164,958
Non-tertiary	36,923	52,671	77,182	108,296
Total lease operating expense	$100,019	$132,170	$202,466	$273,254
Lease operating expense per BOE				
Tertiary	$17.68	$20.52	$17.28	$21.59
Non-tertiary	16.04	18.59	15.65	18.80
Total lease operating expense per BOE	17.04	19.70	16.62	20.39

Our lease operating costs 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, resulting in a decrease in total lease operating expenses of $32.2 million (24%) and $70.8 million (26%) on an absolute-dollar basis, or $2.66 (14%) and $3.77 (18%) on a per-BOE basis, during the three and six months ended June 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 as more wells are uneconomic to repair based on low commodity prices, (2) lower power costs due to lower rates and usage, (3) lower CO_2 expense resulting from a decrease in CO_2 injection volumes, (4) lower company labor costs resulting from a reduction in force, and (5) lower third-party contractor and vendor expenses.

On a per-BOE basis, our lease operating expenses were $17.04 in the second quarter of 2016, compared to $16.23 in the first quarter of 2016, with the change attributable to higher workover costs and lower production volumes. Sequentially, lease operating expenses declined 2% on an absolute-dollar basis and increased 5% on a per-BOE basis between the first quarter of 2016 and the second quarter of 2016. We have deferred certain well workovers and repairs in this current commodity price environment, resulting in us shutting in certain wells that are uneconomic to either produce or repair. As a result, it is unlikely that we will be able to sustain these current low lease operating expense levels in future periods as we expect production levels to gradually decline throughout the year and if prices improve, we may decide to increase our spending for workover and repair work.

Tertiary lease operating expenses decreased $16.4 million and $39.7 million on an absolute-dollar basis, or $2.84 and $4.31 on a per-barrel basis, during the three and six months ended June 30, 2016, respectively, compared to the levels in the same periods in 2015. The year-over-year declines were primarily due to (1) lower CO_2 expense resulting from a decrease in CO_2 injection volumes during both comparative periods, (2) lower power costs due to lower rates and usage, (3) lower company labor costs resulting from a reduction in force, (4) lower third-party contractor and vendor expenses such as contract labor and chemical costs, and (5) lower workover costs and repairs. When comparing the second quarter of 2016 to the first quarter of 2016, tertiary lease operating expenses increased $0.79 (5%) on a per-barrel basis primarily due to production declines during the period.

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 second quarters of 2016 and 2015, approximately 55% and 58%, respectively, 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 second quarter of 2016 was approximately $0.38 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 second quarter of 2016 was higher than the $0.33 per Mcf during the second quarter of 2015 and the $0.30 per Mcf comparable measure during the first quarter of 2016, due primarily to a higher percentage of our CO_2 utilization being industrial-sourced CO_2, which has a higher average cost than our naturally occurring CO_2 sources, and an increase in the price of CO_2 due to higher processing and operating expenses. The sequential increase in the price of CO_2 was further impacted by an increase in royalty costs due to the increase in NYMEX prices during the period. 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 $0.50 per Mcf and $0.44 per Mcf during the second 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 late this year, 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.

Non-tertiary lease operating expenses decreased $15.7 million (30%) on an absolute-dollar basis and $2.55 (14%) on a per-BOE basis between the three months ended June 30, 2016 and 2015, and decreased $31.1 million (29%) and $3.15 (17%) between the six months ended June 30, 2016 and 2015. On a sequential-quarter basis, our non-tertiary lease operating expenses decreased $3.3 million (8%) on an absolute-dollar basis and increased $0.72 (5%) on a per-BOE basis during the second quarter of 2016. The year-over-year and sequential quarter decreases on an absolute-dollar basis were primarily due to (1) a decrease in workover costs and repairs as a result of reduced failures through root-cause analysis and fewer well repairs as more wells are uneconomic to repair based on low commodity prices, (2) lower power costs due to lower usage, (3) lower company labor costs resulting from a reduction in force, and (4) lower third-party contractor and vendor expenses during the 2016 period. The sequential-quarter increase on a per-BOE basis was impacted by lower production during the second quarter of 2016.

Marketing and Plant Operating Expenses

Marketing and plant operating expenses primarily consist of amounts incurred relating to the marketing, processing, and transportation of oil and natural gas production, as well as expenses related to our Riley Ridge gas processing facility. Marketing and plant operating expenses decreased $1.2 million (9%) during the three months ended June 30, 2016 and increased $0.3 million (1%) during the six months ended June 30, 2016, compared to the same periods in 2015.

Taxes Other Than Income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income decreased $14.1 million (42%) and $20.6 million (34%) during the three and six months ended June 30, 2016, 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 the second quarter of 2016.

General and Administrative Expenses (“G&A”)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
In thousands, except per-BOE data and employees	2016	2015	2016	2015
Gross cash compensation and administrative costs	$61,742	$84,365	$141,480	$179,645
Gross stock-based compensation	4,241	8,684	7,125	19,743
Operator labor and overhead recovery charges	(32,865)	(41,427)	(67,998)	(83,555)
Capitalized exploration and development costs	(10,573)	(13,675)	(24,161)	(31,606)
Net G&A expense	$22,545	$37,947	$56,446	$84,227
G&A per BOE:				
Net administrative costs	$3.33	$4.67	$4.35	$5.28
Net stock-based compensation	0.51	0.99	0.28	1.01
Net G&A expense	$3.84	$5.66	$4.63	$6.29
Employees as of June 30	1,084	1,442		

Gross cash compensation and administrative costs on an absolute-dollar basis decreased $22.6 million (27%) and $38.2 million (21%) during the three and six months ended June 30, 2016, compared to those costs in the same period in 2015, primarily due to lower employee-related costs such as salaries, bonus accruals and long-term incentives. The decrease during the six months ended June 30, 2016 was offset in part by higher severance costs incurred during the first quarter of 2016 compared to severance costs in the second quarter of 2015. 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 28% between March 31, 2015 and June 30, 2016. The severance-related payments associated with the 2016 workforce reduction were approximately $9.3 million.

Net G&A expense on a per-BOE basis decreased 32% and 26% during the three and six months ended June 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 $4.4 million (51%) and $12.6 million (64%) during the three and six months ended June 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 the third quarter for 2016. As a result of our customary annual long-term incentive award grant to all employees occurring on July 8, 2016, we currently expect our overall quarterly G&A costs to increase during the second half of 2016 compared to second quarter 2016 levels.

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 June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data and interest rates	2016	2015	2016	2015
Cash interest [(1)]	$43,148	$46,322	$87,793	$92,609
Interest on 2021 Senior Secured Notes not reflected as interest for financial reporting purposes [(1)]	(7,036)	—	(7,036)	—
Noncash interest expense	6,235	2,279	9,541	4,500
Less: capitalized interest	(6,289)	(8,738)	(12,069)	(17,147)
Interest expense, net	$36,058	$39,863	$78,229	$79,962
Interest expense, net per BOE	$6.14	$5.94	$6.42	$5.97
Average debt principal outstanding	$3,006,304	$3,583,316	$3,166,222	$3,599,527
Average interest rate [(2)]	5.7%	5.2%	5.5%	5.1%

(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 semi-annually 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 six months ended June 30, 2016, decreased when compared to the same periods in 2015 as a result of (1) repurchasing a total of $152.3 million principal amount of our existing senior subordinated notes in open-market transactions during the first quarter of 2016 and (2) entering into privately negotiated exchange transactions during the second quarter of 2016 to exchange approximately $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). 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 FASB ASC 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 semi-annual 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 on the 2021 Senior Secured Notes will be significantly lower than the actual cash interest payment. For the three months ended June 30, 2016, $7.0 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 three and six months ended June 30, 2016 increased when compared to the same prior year periods due to the $4.5 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. The six-month period was further impacted by the $1.0 million write-off of debt issuance costs associated with our senior secured bank credit facility following the February 2016 amendment which reduced our lender commitments. Capitalized interest during the three and six months ended June 30, 2016 decreased $2.4 million (28%) and $5.1 million (30%), 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 June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2016	2015	2016	2015
Depletion and depreciation of oil and natural gas properties	$38,141	$115,703	$85,558	$232,050
Depletion and depreciation of CO_2 properties	4,471	6,546	10,044	14,758
Amortization of asset retirement obligations	2,975	2,386	5,877	4,713
Depreciation of pipelines, plants and other property and equipment	20,954	23,305	42,428	46,377
Total DD&A	$66,541	$147,940	$143,907	$297,898
DD&A per BOE:				
Oil and natural gas properties	$7.01	$17.60	$7.50	$17.67
CO_2 properties, pipelines, plants and other property and equipment	4.33	4.45	4.31	4.56
Total DD&A cost per BOE	$11.34	$22.05	$11.81	$22.23
Write-down of oil and natural gas properties	$479,400	$1,705,800	$735,400	$1,852,000

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 65% and 61% on an absolute-dollar basis during the three and six months ended June 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 60% and 58% during the three and six months ended June 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 quarter 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 second 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 June 30, 2016, we currently expect our DD&A rate in the third quarter of 2016 to decrease slightly from the second quarter of 2016 rate. However, the overall decrease in our third 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 15% on an absolute-dollar basis and 3% on a per-BOE basis during the three months ended June 30, 2016, compared to the same period in 2015, primarily due to lower depletion associated with our CO_2 properties resulting from a decrease in CO_2 production during the period.

Write-Down of Oil and Natural Gas Properties

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. As a result of the precipitous and continuing decline in NYMEX oil prices since the fourth quarter of 2014, the average first-day-of-the-month NYMEX oil price used in estimating our proved reserves has fallen throughout 2015 and the first half of 2016, from $71.68 per Bbl for the second quarter of 2015 to $43.12 per Bbl for the second quarter of 2016. In addition, the average first-day-of-the-month NYMEX natural gas price used in estimating our proved reserves was $3.38 per MMBtu for the second quarter of 2015 and $2.33 per MMBtu for the second quarter of 2016. These second quarter prices represent a decrease of 14% for crude oil and 11% for natural gas prices compared to adjusted 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 $479.4 million and $256.0 million during the three months ended June 30 and March 31, 2016, respectively, and $1.7 billion and $146.2 million during the three months ended June 30 and March 31, 2015, respectively. We currently do not expect that we will record a significant write-down in the third quarter of 2016 if oil and natural gas prices remain at or near late-July 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.

Other Expenses

Other expenses totaled $34.7 million and $36.2 million during the three and six months ended June 30, 2016, respectively, 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 June 30,		Six Months Ended June 30,	
In thousands, except per-BOE amounts and tax rates	2016	2015	2016	2015
Current income tax benefit	$—	$(1,696)	$(5)	$(121)
Deferred income tax benefit	(222,940)	(634,472)	(318,055)	(700,508)
Total income tax benefit	$(222,940)	$(636,168)	$(318,060)	$(700,629)
Average income tax benefit per BOE	$(37.98)	$(94.84)	$(26.11)	$(52.28)
Effective tax rate	36.9 %	35.6 %	36.0 %	35.8 %
Total net deferred tax liability	$519,207	$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 June 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 June 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 June 30, 2016.

Our income taxes are based on estimated statutory rates of approximately 38% in 2016 and 2015. Our effective tax rate for the three months ended June 30, 2016 was lower than our estimated statutory rate, primarily due to the full cost pool ceiling test write-down recorded during the quarter. Our effective tax rate for the six months ended June 30, 2016 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 six months ended June 30, 2015 was lower than our estimated statutory rate, primarily due to the impact of the tax valuation allowance discussed above, which reduced the net deferred tax benefit recognized. The deferred income tax benefits during the three and six months ended June 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, 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 June 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 June 30,		Six Months Ended June 30,	
Per-BOE data	2016	2015	2016	2015
Oil and natural gas revenues	$42.02	$54.69	$35.67	$49.58
Receipt on settlements of commodity derivatives	8.86	18.51	10.20	20.34
Lease operating expenses	(17.04)	(19.70)	(16.62)	(20.39)
Production and ad valorem taxes	(2.90)	(4.43)	(2.81)	(3.93)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.85)	(1.86)	(1.84)	(1.66)
Production netback	29.09	47.21	24.60	43.94
CO_2 sales, net of operating and exploration expenses	0.95	0.93	0.92	0.91
General and administrative expenses	(3.84)	(5.66)	(4.63)	(6.29)
Interest expense, net	(6.14)	(5.94)	(6.42)	(5.97)
Other	(4.22)	0.97	(2.16)	0.77
Changes in assets and liabilities relating to operations	(5.46)	5.57	(7.14)	(1.52)
Cash flows from operations	10.38	43.08	5.17	31.84
DD&A	(11.34)	(22.05)	(11.81)	(22.23)
Write-down of oil and natural gas properties	(81.67)	(254.29)	(60.37)	(138.21)
Deferred income taxes	37.98	94.58	26.11	52.28
Gain on debt extinguishment	2.09	—	8.81	—
Noncash fair value adjustments on commodity derivatives [1]	(25.59)	(25.80)	(20.14)	(17.79)
Other noncash items	3.30	(6.73)	5.78	0.36
Net loss	$(64.85)	$(171.21)	$(46.45)	$(93.75)

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

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.

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

FORWARD-LOOKING INFORMATION

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section Management’s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, future hydrocarbon prices, the length or severity of the current commodity price downturn, levels of world monetary, currency or trade volatility, 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 costs, current or future expectations or estimations of our cash flows, availability of capital, borrowing capacity, 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 pipeline 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, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and their availability, helium reserves, potential reserves, percentages of recoverable original oil in place, 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, finding costs, 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 operations and future plans. Such forward-looking statements generally are accompanied by words such as “plan,” “estimate,” “expect,” “predict,” “to our knowledge,” “anticipate,” “projected,” “preliminary,” “should,” “assume,” “believe,” “may” or other words that convey 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.

Table of Contents
Denbury Resources Inc.

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 June 30, 2016, we had $320.0 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 June 30, 2016:

In thousands	2017	2019	2021	2022	2023	Total
Variable rate debt:						
Senior Secured Bank Credit Facility (weighted average interest rate of 2.8% at June 30, 2016)	$ —	$320,000	$ —	$ —	$ —	$320,000
Fixed rate debt:						
9% Senior Secured Second Lien Notes due 2021	—	—	614,919	—	—	614,919
6 % Senior Subordinated Notes due 2021	—	—	220,939	—	—	220,939
5½% Senior Subordinated Notes due 2022	—	—	—	796,712	—	796,712
4 % Senior Subordinated Notes due 2023	—	—	—	—	622,297	622,297
Other Subordinated Notes	2,250	—	—	—	—	2,250

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

Oil and Natural Gas Derivative Contracts

Historically, we have entered into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, and fixed-price swaps enhanced with a sold put. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices. In order to protect our liquidity and provide price certainty to a portion of our oil production, we have hedged approximately two-thirds of our estimated oil production out through the first quarter of 2017 and hedged approximately half of our estimated production in the second quarter of 2017 using both NYMEX and LLS fixed-price swaps and 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 June 30, 2016, our commodity derivative contracts were recorded at their fair value, which was a net liability of $102.4 million, a $150.2 million decrease from the $47.8 million net asset recorded at March 31, 2015, and a $245.2 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 six months ended June 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 June 30, 2016.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of June 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:

In thousands	Receipt / (Payment) Crude Oil Derivative Contracts
Based on:	
Futures prices as of June 30, 2016	$(104,472)
10% increase in prices	(168,146)
10% decrease in prices	(45,122)

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 June 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 second 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.

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

On June 24, 2016, we entered into a settlement agreement with Evolution Petroleum Corporation resolving all outstanding disputes and claims the parties have or may have against each other, including pending litigation claims, involving the Delhi Field in northeastern Louisiana. On July 11, 2016, the pending Delhi Field litigation between the parties was dismissed by the Court with prejudice. For further discussion of the settlement, see Note 7, Commitments and Contingencies, to the Unaudited Condensed Consolidated Financial Statements.

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

Sales of Unregistered Securities

As part of the privately negotiated senior note exchanges which took place in May 2016, as more fully described in Note 2, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements, we issued 40.7 million shares of Denbury common stock that were not and will not be registered under the Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder. The shares of common stock were offered in reliance on the exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended.

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the second 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)
April 2016	4,876	$ 3.80	—	$ 210.1
May 2016	615	3.72	—	210.1
June 2016	5,642	4.13	—	210.1
Total	11,133		—	

(1) Stock repurchases during the second 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 June 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
4(a)	Indenture for 9% Senior Secured Second Lien Notes due 2021, dated as of May 10, 2016, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
10(a)	Collateral Trust Agreement, dated as of May 10, 2016, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 11, 2016, File. No. 001-12935).
10(b)	Intercreditor Agreement, dated as of May 10, 2016, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
10(c)	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of May 24, 2016 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 27, 2016, File No. 001-12935).
10(d)*	2016 Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
10(e)*	2016 Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files.

*Included herewith.

Table of Contents

SIGNATURES

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

	DENBURY RESOURCES INC.
August 5, 2016	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
August 5, 2016	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

INDEX TO EXHIBITS

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