

DENBURY RESOURCES INC
Form 10-Q
May 10, 2018
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q
(Mark One)

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

For the quarterly period ended March 31, 2018
OR

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

For the transition period from _____ to _____

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

Delaware 20-0467835
(State or other jurisdiction of incorporation or organization) (I.R.S. Employer Identification No.)

5320 Legacy Drive,
Plano, TX 75024
(Address of principal executive offices) (Zip Code)

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

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

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

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

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

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company Emerging growth company

(Do not check if a smaller reporting company)

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If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

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

Class	Outstanding as of April 30, 2018
Common Stock, \$.001 par value	440,634,347

Denbury Resources Inc.

Table of Contents

	Page
<u>PART I. FINANCIAL INFORMATION</u>	
<u>Item 1. Financial Statements</u>	
<u>Unaudited Condensed Consolidated Balance Sheets as of March 31, 2018 and December 31, 2017</u>	3
<u>Unaudited Condensed Consolidated Statements of Operations for the Three Months Ended March 31, 2018 and 2017</u>	4
<u>Unaudited Condensed Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2018 and 2017</u>	5
<u>Notes to Unaudited Condensed Consolidated Financial Statements</u>	6
<u>Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations</u>	17
<u>Item 3. Quantitative and Qualitative Disclosures about Market Risk</u>	33
<u>Item 4. Controls and Procedures</u>	35
<u>PART II. OTHER INFORMATION</u>	
<u>Item 1. Legal Proceedings</u>	36
<u>Item 1A. Risk Factors</u>	36
<u>Item 2. Unregistered Sales of Equity Securities and Use of Proceeds</u>	37
<u>Item 3. Defaults Upon Senior Securities</u>	37
<u>Item 4. Mine Safety Disclosures</u>	37
<u>Item 5. Other Information</u>	37
<u>Item 6. Exhibits</u>	38
<u>Signatures</u>	39

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)

	March 31, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	\$85	\$58
Accrued production receivable	157,845	146,334
Trade and other receivables, net	43,553	45,193
Derivative assets	1,859	—
Other current assets	11,512	10,670
Total current assets	214,854	202,255
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	10,824,027	10,775,792
Unevaluated properties	960,039	951,397
CO ₂ properties	1,191,107	1,191,058
Pipelines and plants	2,286,346	2,286,047
Other property and equipment	334,808	339,218
Less accumulated depletion, depreciation, amortization and impairment	(11,424,173)	(11,376,646)
Net property and equipment	4,172,154	4,166,866
Other assets	99,774	102,178
Total assets	\$4,486,782	\$4,471,299
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$149,676	\$177,220
Oil and gas production payable	75,915	76,588
Derivative liabilities	114,512	99,061
Current maturities of long-term debt (including future interest payable of \$100,083 and \$75,347, respectively – see Note 4)	129,667	105,188
Total current liabilities	469,770	458,057
Long-term liabilities		
Long-term debt, net of current portion (including future interest payable of \$256,140 and \$241,472, respectively – see Note 4)	2,923,378	2,979,086
Asset retirement obligations	167,763	165,756
Derivative liabilities	1,876	—
Deferred tax liabilities, net	213,151	198,099
Other liabilities	20,626	22,136
Total long-term liabilities	3,326,794	3,365,077
Commitments and contingencies (Note 7)		
Stockholders' equity		
Preferred stock, \$.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
	403	403

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Common stock, \$.001 par value, 600,000,000 shares authorized; 402,927,941 and 402,549,346 shares issued, respectively		
Paid-in capital in excess of par	2,511,131	2,507,828
Accumulated deficit	(1,816,232)	(1,855,810)
Treasury stock, at cost, 787,867 and 457,041 shares, respectively	(5,084)	(4,256)
Total stockholders' equity	690,218	648,165
Total liabilities and stockholders' equity	\$4,486,782	\$4,471,299

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 March 31,	
	2018	2017
Revenues and other income		
Oil, natural gas, and related product sales	\$ 340,021	\$ 266,178
CO ₂ sales and transportation fees	7,552	5,388
Interest income and other income	5,661	3,888
Total revenues and other income	353,234	275,454
Expenses		
Lease operating expenses	118,356	113,840
Marketing and plant operating expenses	12,424	14,065
CO ₂ discovery and operating expenses	462	593
Taxes other than income	27,319	22,440
General and administrative expenses	20,232	28,241
Interest, net of amounts capitalized of \$8,452 and \$4,654, respectively	17,239	27,178
Depletion, depreciation, and amortization	52,451	51,195
Commodity derivatives expense (income)	48,825	(24,602)
Other expenses	2,328	—
Total expenses	299,636	232,950
Income before income taxes	53,598	42,504
Income tax provision	14,020	20,974
Net income	\$ 39,578	\$ 21,530
Net income per common share		
Basic	\$ 0.10	\$ 0.06
Diluted	\$ 0.09	\$ 0.05
Weighted average common shares outstanding		
Basic	392,742	389,397
Diluted	451,543	392,997

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

Denbury Resources Inc.

Unaudited Condensed Consolidated Statements of Cash Flows

(In thousands)

	Three Months Ended March 31,	
	2018	2017
Cash flows from operating activities		
Net income	\$39,578	\$21,530
Adjustments to reconcile net income to cash flows from operating activities		
Depletion, depreciation, and amortization	52,451	51,195
Deferred income taxes	15,052	34,909
Stock-based compensation	2,592	4,106
Commodity derivatives expense (income)	48,825	(24,602)
Payment on settlements of commodity derivatives	(33,357)	(26,940)
Debt issuance costs and discounts	1,137	1,901
Other, net	(838)	(344)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	(11,510)	6,453
Trade and other receivables	348	(12,185)
Other current and long-term assets	(1,886)	643
Accounts payable and accrued liabilities	(19,817)	(23,890)
Oil and natural gas production payable	(673)	(7,335)
Other liabilities	(275)	(1,179)
Net cash provided by operating activities	91,627	24,262
Cash flows from investing activities		
Oil and natural gas capital expenditures	(56,669)	(52,152)
Acquisitions of oil and natural gas properties	(35)	(16,222)
Pipelines and plants capital expenditures	(156)	(246)
Net proceeds from sales of oil and natural gas properties and equipment	1,522	415
Other	4,542	792
Net cash used in investing activities	(50,796)	(67,413)
Cash flows from financing activities		
Bank repayments	(571,653)	(343,000)
Bank borrowings	546,653	397,000
Pipeline financing and capital lease debt repayments	(6,287)	(7,055)
Other	(9,291)	(3,469)
Net cash provided by (used in) financing activities	(40,578)	43,476
Net increase in cash, cash equivalents, and restricted cash	253	325
Cash, cash equivalents, and restricted cash at beginning of period	40,614	40,905
Cash, cash equivalents, and restricted cash at end of period	\$40,867	\$41,230

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 CO₂ 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, 2017 (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 March 31, 2018, our consolidated results of operations for the three months ended March 31, 2018 and 2017, and our consolidated cash flows for the three months ended March 31, 2018 and 2017.

Reclassifications

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

Cash, Cash Equivalents, and Restricted Cash

The following table provides a reconciliation of cash, cash equivalents, and restricted cash as reported within the Unaudited Condensed Consolidated Balance Sheets to “Cash, cash equivalents, and restricted cash at end of period” as reported within the Unaudited Condensed Consolidated Statements of Cash Flows:

	Three Months Ended March 31,	
In thousands	2018	2017
Cash and cash equivalents	\$85	\$1,747
Restricted cash included in Other assets	40,782	39,483
Total cash, cash equivalents, and restricted cash shown in the statement of cash flows	\$40,867	\$41,230

Amounts included in restricted cash included in “Other assets” in the accompanying Unaudited Condensed Consolidated Balance Sheets represent escrow accounts that are legally restricted for certain of our asset retirement obligations.

Net Income per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of nonvested restricted stock, nonvested performance-based equity awards, and shares into which our convertible senior notes are convertible.

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

The following table sets forth the reconciliations of net income and weighted average shares used for purposes of calculating the basic and diluted net income per common share for the periods indicated:

In thousands	Three Months Ended March 31,	
	2018	2017
Numerator		
Net income – basic	\$39,578	\$21,530
Effect of potentially dilutive securities		
Interest on convertible senior notes	501	—
Net income – diluted	\$40,079	\$21,530
Denominator		
Weighted average common shares outstanding – basic	392,742	389,397
Effect of potentially dilutive securities		
Restricted stock and performance-based equity awards	5,169	3,600
Convertible senior notes	53,632	—
Weighted average common shares outstanding – diluted	451,543	392,997

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although time-vesting restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the three months ended March 31, 2018 and 2017, the nonvested restricted stock and performance-based equity awards are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, and for the shares underlying the convertible senior notes as if the convertible senior notes were converted at the beginning of the 2018 period. In April 2018, our 3½% Convertible Senior Notes due 2024 (the “2024 Convertible Senior Notes”) converted into shares of Denbury common stock, resulting in the issuance of 38.5 million shares of our common stock upon conversion. These shares will be included in basic weighted average common shares outstanding beginning the date of conversion. See Note 4, Long-Term Debt, for further discussion.

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

In thousands	Three Months Ended March 31,	
	2018	2017
Stock appreciation rights	2,954	5,044
Restricted stock and performance-based equity awards	431	1,229

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Recent Accounting Pronouncements

Recently Adopted

Cash Flows. In November 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2016-18, Statement of Cash Flows (“ASU 2016-18”). ASU 2016-18 addresses the diversity that exists in the classification and presentation of changes in restricted cash on the statement of cash flows, and requires that a statement of cash flows explain the change in total cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, entities will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statement of cash flows. Effective January 1, 2018, we adopted ASU 2016-18, which has been applied retrospectively for all comparative periods presented. Accordingly, restricted cash associated with our escrow accounts of \$40.6 million and \$39.3 million for the three-month periods ended March 31, 2018 and 2017, respectively, have been included in “Cash, cash equivalents, and restricted cash at beginning of period” on our Unaudited Condensed Consolidated Statements of Cash Flows and \$39.5 million included in “Cash, cash equivalents, and restricted cash at end of period” for the three-month period ended March 31, 2017. The adoption of ASU 2016-18 did not have an impact on our consolidated balance sheets or results of operations.

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 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. Effective January 1, 2018, we adopted ASU 2014-09 using the modified retrospective method. The adoption of ASU 2014-09 did not have an impact on our consolidated financial statements, but required enhanced footnote disclosures. See Note 2, Revenue Recognition, for additional information.

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. In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842) – Land Easement Practical Expedient for Transition to Topic 842, which provides an optional practical expedient to existing or expired land easements that were not previously accounted for as leases under Topic 842, which permits a company to evaluate only new or modified land easements under the new guidance. Management is currently assessing the impact the adoption of ASU 2016-02 and ASU 2018-01 will have on our consolidated financial statements.

Note 2. Revenue Recognition

The Company records revenue in accordance with FASB Accounting Standards Codification (“ASC”) Topic 606, Revenue from Contracts with Customers, which the Company adopted on January 1, 2018, and applied to all existing contracts using the modified retrospective method. The core principle of FASB ASC Topic 606 is that an entity should recognize revenue for the transfer of goods or services equal to the amount of consideration that it expects to be entitled to receive for those goods or services. This principle is achieved through applying a five-step process for customer contract revenue recognition:

- Identify the contract or contracts with a customer – We derive the majority of our revenues from oil and natural gas sales contracts and CO₂ sales and transportation contracts. The contracts specify each party’s rights regarding the goods or services to be transferred and contain commercial substance as they impact the Company’s financial statements. A high percentage of the Company’s receivables balance is current, and we have not historically entered into contracts with counterparties that pose a credit risk without requiring adequate economic protection to ensure collection.

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

- Identify the performance obligations in the contract – Each of our revenue contracts specify a volume per day, or production from a lease designated in the contract (a distinct good), to be delivered at the delivery point over the term of the contract (the identified performance obligation). The customer takes delivery and physical possession of the product at the delivery point, which generally is also the point at which title transfers and the customer obtains the risks and rewards of ownership (the identified performance obligation is satisfied).

- Determine the transaction price – Typically, our oil and natural gas contracts define the price as a formula price based on the average market price, as specified on set dates each month, for the specific commodity during the month of delivery. Certain of Denbury’s CO₂ contracts define the price as a fixed contractual price adjusted to an inflation index to reflect market pricing. Given the industry practice to invoice customers the month following the month of delivery and our high probability of collection of payment, no significant financing component is included in our contracts.

- Allocate the transaction price to the performance obligations in the contract – The majority of our revenue contracts are short-term, with terms of one year or less, to which we have applied the practical expedient permitted under the standard eliminating the requirement to disclose the transaction price allocated to remaining performance obligations. In limited instances, we have revenue contracts with terms greater than one year; however, the future delivery volumes are wholly unsatisfied as they represent separate performance obligations with variable consideration. We utilized the practical expedient which eliminates the requirement to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to wholly unsatisfied performance obligations. As there is only one performance obligation associated with our contracts, no allocation of the transaction price is necessary.

- Recognize revenue when, or as, we satisfy a performance obligation – Once we have delivered the volume of commodity to the delivery point and the customer takes delivery and possession, we are entitled to payment and we invoice the customer for such delivered production. Payment under most oil and CO₂ contracts is made within a month following product delivery and for natural gas and NGL contracts is generally made within two months following delivery. Timing of revenue recognition may differ from the timing of invoicing to customers; however, as the right to consideration after delivery is unconditional based on only the passage of time before payment of the consideration is due, upon delivery we record a receivable in “Accrued production receivable” in our Unaudited Condensed Consolidated Balance Sheets, which was \$157.8 million and \$146.3 million as of March 31, 2018 and December 31, 2017, respectively.

Disaggregation of Revenue

The following table summarizes our revenues by product type for the three months ended March 31, 2018 and 2017:

In thousands	Three Months Ended March 31,	
	2018	2017
Oil sales	\$337,406	\$263,974
Natural gas sales	2,615	2,204
CO ₂ sales and transportation fees	7,552	5,388
Total revenues	\$347,573	\$271,566

Note 3. Assets Held for Sale

We began actively marketing for sale certain non-productive surface acreage in the Houston area during July 2017. As of March 31, 2018, the carrying value of the land held for sale was \$33.1 million, which is included in “Other property and equipment” on our Unaudited Condensed Consolidated Balance Sheets.

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 4. Long-Term Debt

The table below reflects long-term debt and capital lease obligations outstanding as of the dates indicated. In April 2018, all \$84.7 million of our outstanding 3½% Convertible Senior Notes due 2024 was extinguished as a result of conversion into common stock (see April 2018 Conversion of 2024 Convertible Senior Notes below):

In thousands	March 31, 2018	December 31, 2017
Senior Secured Bank Credit Agreement	\$450,000	\$475,000
9% Senior Secured Second Lien Notes due 2021	614,919	614,919
9¼% Senior Secured Second Lien Notes due 2022	455,668	381,568
5% Convertible Senior Notes due 2023	59,439	—
3½% Convertible Senior Notes due 2024	84,650	84,650
6 % Senior Subordinated Notes due 2021	203,545	215,144
5½% Senior Subordinated Notes due 2022	314,662	408,882
4 % Senior Subordinated Notes due 2023	307,978	376,501
Pipeline financings	189,547	192,429
Capital lease obligations	22,585	26,298
Total debt principal balance	2,702,993	2,775,391
Future interest payable ⁽¹⁾	356,223	316,818
Debt issuance costs	(6,171)	(7,935)
Total debt, net of debt issuance costs	3,053,045	3,084,274
Less: current maturities of long-term debt ⁽¹⁾	(129,667)	(105,188)
Long-term debt and capital lease obligations	\$2,923,378	\$2,979,086

Future interest payable represents most of the interest due over the terms of our 9% Senior Secured Second Lien Notes due 2021, 9¼% Senior Secured Second Lien Notes due 2022 (the “2022 Senior Secured Notes”), 5% Convertible Senior Notes due 2023 (the “2023 Convertible Senior Notes”), and 2024 Convertible Senior Notes and (1) has been accounted for as debt in accordance with FASC 470-60, Troubled Debt Restructuring by Debtors. Our current maturities of long-term debt as of March 31, 2018 include \$100.1 million of future interest payable related to these notes that is due within the next twelve months. See January 2018 Note Exchanges 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, convertible senior, 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 (as amended, the “Bank Credit Agreement”). The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2019 and semiannual borrowing base redeterminations in May and November of each year. As part of our spring 2018 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were

reaffirmed at \$1.05 billion, with the next such redetermination being scheduled for November 2018. If our outstanding debt under the Bank Credit Agreement were to ever exceed the borrowing base, we would be required to repay the excess amount over a period not to exceed six months. The weighted average interest rate on borrowings outstanding under the Bank Credit Agreement was 4.5% as of March 31, 2018. We incur a commitment fee of 0.50% on the undrawn portion of the aggregate lender commitments under the Bank Credit Agreement.

The Bank Credit Agreement contains certain financial performance covenants through the maturity of the facility, including the following:

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 3.0 to 1.0 through the first quarter of 2018, and thereafter not to exceed 2.5 to 1.0. Currently, only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;

- ▲ a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- ▲ a requirement to maintain a current ratio of 1.0 to 1.0.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement and the amendments thereto, each of which are filed as exhibits to our periodic reports filed with the SEC.

January 2018 Note Exchanges

During January 2018, we closed transactions to exchange a total of \$174.3 million aggregate principal amount of our then existing senior subordinated notes for \$74.1 million aggregate principal amount of new 2022 Senior Secured Notes and \$59.4 million aggregate principal amount of new 2023 Convertible Senior Notes, resulting in a net reduction in our debt principal from these exchanges of \$40.8 million. The exchanged notes consisted of \$11.6 million aggregate principal amount of our 6 % Senior Subordinated Notes due 2021 (the “2021 Notes”), \$94.2 million aggregate principal amount of our 5½% Senior Subordinated Notes due 2022 (the “2022 Notes”) and \$68.5 million aggregate principal amount of our 4 % Senior Subordinated Notes due 2023 (the “2023 Notes”).

In accordance with FASC 470-60, the exchange was accounted for as a troubled debt restructuring due to the level of concession provided by our senior subordinated note holders. Under this guidance, future interest applicable to the new 2022 Senior Secured Notes and 2023 Convertible Senior 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 of March 31, 2018, \$37.6 million of future interest on the new 2022 Senior Secured Notes and 2023 Convertible Senior Notes was recorded as debt, which will be reduced as semiannual interest payments are made, with the remaining \$6.8 million of future interest to be recognized as interest expense over the term of these notes. Therefore, future interest expense reflected in our Unaudited Condensed Consolidated Statements of Operations on the new 2022 Senior Secured Notes and 2023 Convertible Senior Notes will be significantly lower than the actual cash interest payments.

9¼% Senior Secured Second Lien Notes due 2022

In January 2018, we issued \$74.1 million of principal amount of 2022 Senior Secured Notes, which principal amount is in addition to the \$381.6 million of 2022 Senior Secured Notes issued during December 2017. The 2022 Senior Secured Notes, which bear interest at a rate of 9.25% per annum, were issued at par in connection with exchanges with a limited number of holders of existing senior subordinated notes in December 2017 and January 2018 (see January 2018 Note Exchanges above). The 2022 Senior Secured Notes mature on March 31, 2022, and interest is payable semiannually in arrears on March 31 and September 30 of each year. We may redeem the 2022 Senior Secured Notes in whole or in part at our option beginning March 31, 2019, at a redemption price of 109.25% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture governing the 2022 Senior Secured Notes. Prior to March 31, 2019, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2022 Senior Secured Notes at a price of 109.25% of par with the proceeds of certain equity offerings. In addition, at any time prior to March 31, 2019, we may redeem the 2022 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 2022 Senior Secured Notes are not subject to any sinking fund requirements.

The 2022 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.

5% Convertible Senior Notes due 2023

In January 2018, we issued \$59.4 million of 2023 Convertible Senior Notes. The 2023 Convertible Senior Notes, which bear interest at a rate of 5% per annum, were issued at par in exchange offers with a limited number of holders of existing senior subordinated notes (see January 2018 Note Exchanges above). The 2023 Convertible Senior Notes mature on December 15, 2023,

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

and interest is payable semiannually in arrears on June 15 and December 15 of each year, beginning in June 2018. We do not have the right to redeem the 2023 Convertible Senior Notes prior to their maturity. The 2023 Convertible Senior Notes are convertible into shares of our common stock at any time, at the option of the holders, at a rate of 281.69 shares of common stock per \$1,000 principal amount of 2023 Convertible Senior Notes, subject to customary adjustments to the conversion rate and threshold price with respect to, among other things, stock dividends and distributions, mergers and reclassifications. The 2023 Convertible Senior Notes will be automatically converted into shares of common stock at this rate if the volume weighted average trading price of the Company's common stock equals or exceeds the threshold price, which initially is \$3.55 per share, for 10 trading days in any period of 15 consecutive trading days, subject to satisfaction of certain other conditions. Additionally, the Company may, based on a determination of its Board of Directors that such changes are in the best interests of the Company, and subject to certain limitations, increase the conversion rate (which increase in conversion rate is limited until January 9, 2019 to no greater than 393.55 shares of common stock per \$1,000 principal amount of 2023 Convertible Senior Notes). Any such conversion rate increase would cause a proportional decrease in the threshold price for mandatory conversions, and thereby would enable the Company to require a mandatory conversion into common stock at a lower price than the initial or then-prevailing threshold price.

April 2018 Conversion of 2024 Convertible Senior Notes

In April 2018, holders of all \$84.7 million aggregate outstanding principal amount of our 2024 Convertible Senior Notes converted their notes into shares of Denbury common stock, at rates specified in the indenture for the notes, resulting in the issuance of 38.5 million shares of our common stock upon conversion. As of April 18, 2018, there were no remaining 2024 Convertible Notes outstanding.

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, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength and expectation of future commodity prices.

We 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 March 31, 2018, 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 March 31, 2018, 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)		Weighted Average Price			
			Range ⁽¹⁾		Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2018 Basis Swaps ⁽²⁾								
Apr – June	Argus LLS	20,000	\$3.13	-4.63	\$4.17	\$—	\$—	\$—
2018 Fixed-Price Swaps								
Apr – Dec	NYMEX	20,500	\$50.00	-56.65	\$51.69	\$—	\$—	\$—
Apr – Dec	Argus LLS	5,000	60.10	-60.25	60.18	—	—	—
2018 Three-Way Collars ⁽³⁾								
Apr – Dec	NYMEX	15,000	\$45.00	-56.60	\$—	\$36.50	\$46.50	\$53.88
2019 Fixed-Price Swaps								
Jan – June	NYMEX	3,500	\$59.00	-59.10	\$59.05	\$—	\$—	\$—
2019 Three-Way Collars ⁽³⁾								
Jan – June	NYMEX	6,500	\$55.00	-66.20	\$—	\$47.00	\$55.00	\$65.54
July – Dec	NYMEX	10,000	55.00	-65.60	—	47.00	55.00	65.37

Ranges presented for fixed-price swaps and basis swaps represent the lowest and highest fixed prices of all open (1) contracts for the period presented. For three-way collars, ranges represent the lowest floor price and highest ceiling price for all open contracts for the period presented.

(2) The basis swap contracts establish a fixed amount for the differential between Argus WTI and Argus LLS prices on a trade-month basis for the period indicated.

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 and basis 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-

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

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. As of March 31, 2018, we had no Level 3 recurring fair value measurements. Previous instruments in this category included non-exchange-traded 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 were developed using a benchmark, which was considered a significant unobservable input.

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

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

In thousands	Fair Value Measurements Using:			Total
	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
March 31, 2018				
Assets				
Oil derivative contracts – current	\$—\$1,859	\$		—\$1,859
Total Assets	\$—\$1,859	\$		—\$1,859
Liabilities				
Oil derivative contracts – current	\$—\$(114,512)	\$		—\$(114,512)
Oil derivative contracts – long-term	—(1,876)			(1,876)
Total Liabilities	\$—\$(116,388)	\$		—\$(116,388)
December 31, 2017				
Liabilities				
Oil derivative contracts – current	\$—\$(99,061)	\$		—\$(99,061)
Total Liabilities	\$—\$(99,061)	\$		—\$(99,061)

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.

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

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 months ended March 31, 2018 and 2017:

	Three Months Ended March 31, 2017
In thousands	
Fair value of Level 3 instruments, beginning of period	\$—(526)
Fair value gains on commodity derivatives	—617
Payments on settlements of commodity derivatives	—
Fair value of Level 3 instruments, end of period	\$—91
The amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to assets or liabilities still held at the reporting date	\$—236

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, convertible senior notes, and senior subordinated notes are based on quoted market prices, which are considered Level 1 measurements under the fair value hierarchy. The estimated fair value of the principal amount of our debt as of March 31, 2018 and December 31, 2017, excluding pipeline financing and capital lease obligations, was \$2,350.8 million and \$2,260.6 million, respectively. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 7. Commitments and Contingencies

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.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC. The helium supply contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after startup of the Riley Ridge gas processing facility, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are specified in the contract at up to \$8.0 million per contract year and are capped at an aggregate of \$46.0 million over the term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium under the helium supply contract. APMTG Helium, LLC filed a case in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, claiming multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company's position is that our contractual obligations are excused by virtue of events that fall within the force majeure provisions in the helium supply contract. The evidentiary phase of the trial closed on November 29, 2017. The parties submitted written closing briefs and rebuttal briefs to the District Court during

Table of Contents

Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

February and April of 2018. We currently expect a ruling from the District Court to be made in the second or third quarter of 2018. The Company plans to continue to vigorously defend its position, but we are unable to predict at this time the outcome of this dispute.

Table of Contents

Denbury Resources Inc.

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

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

The following discussion and analysis should be read in conjunction with our 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, 2017 (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 the Form 10-K, 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 CO₂ enhanced oil recovery operations.

Oil Price Impact on Our Business. Our financial results are significantly impacted by changes in oil prices, as 97% of our production is oil. Oil prices have continued to improve from the levels experienced over the last few years, when oil prices generally ranged between \$40-\$50 per Bbl. NYMEX oil prices averaged approximately \$63 per Bbl in the first quarter of 2018 compared to approximately \$52 per Bbl in the first quarter of 2017. Increases in oil prices impact all aspects of our business; most notably our cash flow from operations, revenues, and capital budgeting decisions. Our 2018 capital spending has been budgeted at approximately \$300 million to \$325 million, excluding capitalized interest and acquisitions, roughly a 30% increase over 2017 capital spending levels. We utilized a NYMEX oil price estimate of \$55 per Bbl in developing our 2018 budget, which based on our current projections would generate a level of cash flow that would fully fund our development capital spending plans. With this capital spending level, we currently anticipate our 2018 production to average between 60,000 and 64,000 BOE/d. We have hedged various portions of our estimated oil production through 2019 in order to protect against the volatility in oil prices and to provide greater certainty around levels of our cash flow in order to execute on our planned 2018 capital spending.

Operating Highlights. We recognized net income of \$39.6 million, or \$0.09 per diluted common share, during the first quarter of 2018, compared to net income of \$21.5 million, or \$0.05 per diluted common share, during the first quarter of 2017. The primary drivers of our change in operating results between the comparative first quarters of 2018 and 2017 were the following:

- Oil and natural gas revenues in the first quarter of 2018 improved by \$73.8 million, or 28%, principally driven by a 28% improvement in realized oil prices, along with a 1% increase in average daily production volumes.
- Our net realized oil price relative to NYMEX prices improved by \$2.93 per Bbl from the prior-year period to \$1.29 per Bbl above NYMEX.

Commodity derivatives expense increased by \$73.4 million (\$48.8 million of expense in the current-year period compared to \$24.6 million of income in the prior-year period). This increase in expense was the result of losses from noncash fair value adjustments between the periods of \$67.0 million and a \$6.4 million increase in payments on derivative settlements.

General and administrative expenses decreased \$8.0 million, primarily as a result of lower employee-related costs due to a workforce reduction in August 2017.

Interest expense, net, decreased on a GAAP basis by \$9.9 million primarily due to the exchange transactions completed during December 2017 and January 2018. See Results of Operations – Interest and Financing Expenses for further discussion.

We generated \$91.6 million of cash flows from operating activities in the first quarter of 2018, an increase of \$67.4 million from the first quarter of 2017 levels. The increase in cash flows from operations was due primarily to higher oil and natural gas revenues of \$73.8 million, a \$9.9 million decrease in interest expense, and an \$8.0 million decrease in general and administrative expenses, slightly offset by an increase in derivative settlement payments of \$6.4 million, a \$4.9 million increase in taxes other than income and a \$4.5 million increase in lease operating expenses.

2018 Debt Reduction Transactions. In early January 2018, we closed transactions in which \$174.3 million aggregate principal amount of our existing senior subordinated notes were exchanged for \$74.1 million aggregate principal amount of 9¼% Senior Secured Second Lien Notes due 2022 (the “2022 Senior Secured Notes”) and \$59.4 million aggregate principal amount of new 5% Convertible Senior Notes due 2023 (the “2023 Convertible Senior Notes”).

Table of Contents

Denbury Resources Inc.

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

April 2018 Conversion of 2024 Convertible Senior Notes. In April 2018, holders of all \$84.7 million outstanding principal amount of our 3½% Convertible Senior Notes due 2024 (the "2024 Convertible Senior Notes") converted their notes into shares of Denbury common stock, at rates specified in the indenture for the notes, resulting in the issuance of 38.5 million shares of our common stock upon conversion. As of April 18, 2018, there were no remaining 2024 Convertible Senior Notes outstanding.

Exploitation Drilling Update. Following the success of our first exploitation horizontal well in the Mission Canyon interval at Cedar Creek Anticline at the end of 2017, we have allocated \$30 million to \$40 million of our 2018 capital budget to exploitation drilling across this broad area. We recently completed two additional Mission Canyon wells, both of which were successful, and have added an additional well to the program for 2018, bringing the total wells planned this year to seven. These first three wells are currently producing at a combined gross rate of between 2,500 and 3,000 barrels of oil per day. In addition, we recently began drilling our first well in the Perry Sand interval at Tinsley Field, and expect to see results of that well during the second quarter. Finally, in the second half of 2018, we plan to drill a well in the Powder River Basin at Hartzog Draw Field to test the prospectivity of deeper intervals on our acreage, which is held by Hartzog Draw unit production.

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. For the three months ended March 31, 2018, we generated cash flows from operations of \$91.6 million, after giving effect to \$33.8 million of cash outflows for working capital changes, which were impacted by increasing revenues during 2018 due to oil price increases and the timing of certain payments.

As of March 31, 2018, we had \$450.0 million drawn on our \$1.05 billion senior secured bank credit facility, compared to \$475.0 million of borrowings outstanding as of December 31, 2017. This leaves us with \$537.8 million of borrowing base availability as of March 31, 2018, after consideration of \$62.2 million of outstanding letters of credit.

We have historically tried to match our development capital spending with our cash flow from operations, and we currently expect to fund our planned capital expenditures with our projected cash flows from operations in 2018. We believe the approximate \$540 million of liquidity available under our bank credit facility is sufficient to cover any excess working capital needs or any foreseeable cash flow shortfall between our cash flows from operations and capital spending. With the maturity of our bank credit facility set for December 2019, the Company intends to proactively work with its bank group during 2018 on extension of that maturity date while remaining focused upon maintaining our current level of available liquidity through that process. The Company may also raise funds through asset sales or joint ventures, or issuance of debt and/or equity, which would enable us to further increase our available liquidity. Related to this, the Company is currently engaged in two asset sale processes. In mid-2017, we began to actively market for sale certain non-producing surface acreage in the Houston area. The acreage contains numerous parcels, and we currently anticipate that a portion of these sales will occur in 2018, with the remainder extending into 2019. Also, in February 2018, we initiated a sale process for our mature EOR properties located in Mississippi and Louisiana and Citronelle Field located in Alabama. In aggregate, these fields accounted for 13% of our first quarter 2018 production and approximately 7% of our 2017 year-end proved reserves. The success, timing and outcome of these processes cannot be predicted at this time, but their successful completion could provide funds to pay down debt or add liquidity for financial or operational uses.

We have reduced our outstanding debt principal by approximately \$953 million on a proforma basis between December 31, 2014 and March 31, 2018, primarily through opportunistic debt exchanges, open market debt repurchases, and the conversion into common stock of all of our outstanding 3½% Convertible Senior Notes due 2024 in April 2018. The movements in the market price of our debt and equity securities may provide opportunities for debt refinancing or additional debt reduction, and we may have discussions with bondholders from time to time regarding potential debt reduction transactions of various types. Potential transactions could include purchases of our debt in the open market, exchange offers, cash tenders for our debt, or future potential debt reduction with proceeds of issuances of equity, asset sales, joint ventures and other cash-generating activities.

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 (as amended, the “Bank Credit Agreement”). As part of our spring 2018 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at \$1.05 billion, with the next such redetermination scheduled for November 2018.

The Bank Credit Agreement contains certain financial performance covenants through the maturity of the facility, including the following:

Table of Contents

Denbury Resources Inc.

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

A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 3.0 to 1.0 through the first quarter of 2018, and thereafter not to exceed 2.5 to 1.0. Currently, only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;

- ▲ a minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- ▲ a requirement to maintain a current ratio of 1.0 to 1.0.

Under these financial performance covenant calculations, as of March 31, 2018, our ratio of consolidated senior secured debt to consolidated EBITDAX was 0.92 to 1.0 (with a maximum permitted ratio of 3.0 to 1.0), our ratio of consolidated EBITDAX to consolidated interest charges was 2.71 to 1.0 (with a required ratio of not less than 1.25 to 1.0), and our current ratio was 3.33 to 1.0 (with a required ratio of not less than 1.0 to 1.0). Based upon our currently forecasted levels of production and costs, hedges in place as of May 7, 2018, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our financial performance covenants during the foreseeable future.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement and the amendments thereto, each of which are filed as exhibits to our periodic reports filed with the SEC.

Recent Debt Reduction Transactions. During January 2018, we closed transactions in which \$11.6 million aggregate principal amount of our 6 % Senior Subordinated Notes due 2021 (the "2021 Notes"), \$94.2 million aggregate principal amount of our 5½% Senior Subordinated Notes due 2022 (the "2022 Notes") and \$68.5 million aggregate principal amount of our 4 % Senior Subordinated Notes due 2023 (the "2023 Notes") were exchanged for \$74.1 million aggregate principal amount of 2022 Senior Secured Notes and \$59.4 million aggregate principal amount of 2023 Convertible Senior Notes, resulting in a net reduction of \$40.8 million in our debt principal since December 31, 2017. When combined with the privately negotiated transactions completed in December 2017 and mandatory debt conversion triggered in April 2018, we have reduced our debt principal by \$269.1 million, which could increase to approximately \$329 million if all of the 2023 Convertible Senior Notes also convert into Company common stock (based upon issuance of up to 16,743,372 shares at the current conversion rate for such notes).

Capital Spending. We currently anticipate that our full-year 2018 capital budget, excluding capitalized interest and acquisitions, will be approximately \$300 million to \$325 million. Capitalized interest is currently estimated at approximately \$30 million for 2018. The 2018 capital budget, excluding capitalized interest and acquisitions, provides for approximate spending as follows:

- \$155 million allocated for tertiary oil field expenditures;
- \$95 million allocated for other areas, primarily non-tertiary oil field expenditures including exploitation;
- \$20 million to be spent on CO₂ sources and pipelines; and
- \$45 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Table of Contents

Denbury Resources Inc.

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

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the three months ended March 31, 2018 and 2017:

In thousands	Three Months Ended	
	March 31, 2018	2017
Capital expenditures by project		
Tertiary oil fields	\$ 18,273	\$ 21,207
Non-tertiary fields	14,922	18,440
Capitalized internal costs ⁽¹⁾	14,085	13,646
Oil and natural gas capital expenditures	47,280	53,293
CO ₂ pipelines, sources and other	347	10
Capital expenditures, before acquisitions and capitalized interest	47,627	53,303
Acquisitions of oil and natural gas properties	35	16,098
Capital expenditures, before capitalized interest	47,662	69,401
Capitalized interest	8,452	4,654
Capital expenditures, total	\$ 56,114	\$ 74,055

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

For the three months ended March 31, 2018, our capital expenditures and property acquisitions were funded with \$91.6 million of cash flows from operations. For the three months ended March 31, 2017, our capital expenditures and property acquisitions were primarily funded with cash flows from operations, with additional funds provided by borrowings on our Bank Credit Agreement.

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

Our commitments and obligations consist of those detailed as of December 31, 2017, 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.

Table of Contents

Denbury Resources Inc.

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

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.

Table of Contents

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 months ended March 31, 2018 and 2017 are included in the following table:

In thousands, except per-share and unit data	Three Months Ended March 31,	
	2018	2017
Operating results		
Net income	\$ 39,578	\$ 21,530
Net income per common share – basic	0.10	0.06
Net income per common share – diluted	0.09	0.05
Net cash provided by operating activities	91,627	24,262
Average daily production volumes		
Bbls/d	58,354	58,303
Mcf/d	11,904	9,778
BOE/d ⁽¹⁾	60,338	59,933
Operating revenues		
Oil sales	\$ 337,406	\$ 263,974
Natural gas sales	2,615	2,204
Total oil and natural gas sales	\$ 340,021	\$ 266,178
Commodity derivative contracts ⁽²⁾		
Payment on settlements of commodity derivatives	\$ (33,357)	\$ (26,940)
Noncash fair value gains (losses) on commodity derivatives ⁽³⁾	(15,468)	51,542
Commodity derivatives income (expense)	\$ (48,825)	\$ 24,602
Unit prices – excluding impact of derivative settlements		
Oil price per Bbl	\$ 64.25	\$ 50.31
	2.44	2.50

Natural gas price per Mcf			
Unit prices – including impact of derivative settlements ⁽²⁾			
Oil price per Bbl	\$	57.89	\$ 45.17
Natural gas price per Mcf		2.44	2.50
Oil and natural gas operating expenses			
Lease operating expenses	\$	118,356	\$ 113,840
Marketing expenses, net of third-party purchases, and plant operating expenses		9,522	10,088
Production and ad valorem taxes		25,032	20,841
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	\$	62.61	\$ 49.35
Lease operating expenses		21.80	21.11
Marketing expenses, net of third-party purchases, and plant operating expenses		1.75	1.87
Production and ad valorem taxes		4.61	3.86
CO ₂ sources – revenues and expenses			
CO ₂ sales and transportation fees	\$	7,552	\$ 5,388
CO ₂ discovery and operating expenses		(462)	(593)
CO ₂ revenue and expenses, net	\$	7,090	\$ 4,795

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

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

Table of Contents

Denbury Resources Inc.

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

Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure and is different from "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations in that the noncash fair value gains (losses) on commodity derivatives represent only the net changes between periods of the fair market values of commodity derivative positions, and exclude the impact of settlements on commodity derivatives during the period, which were payments on settlements of \$33.4 million and \$26.9 million for the three months ended March 31, 2018 and 2017, respectively. We believe that noncash fair value gains (losses) on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from receipts or payments upon settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income (loss) to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value gains (losses) on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for "Commodity derivatives expense (income)" in the Unaudited Condensed Consolidated Statements of Operations.

Table of Contents

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 2017 and for the first quarter of 2018 is shown below:

Operating Area	Average Daily Production (BOE/d)				
	First Quarter 2017	Second Quarter 2017	Third Quarter 2017	Fourth Quarter 2017	First Quarter 2018
Tertiary oil production					
Gulf Coast region					
Mature properties ⁽¹⁾	8,097	7,727	7,431	7,225	7,174
Delhi	4,991	4,965	4,619	4,906	4,169
Hastings	4,288	4,400	4,867	5,747	5,704
Heidelberg	4,730	4,996	4,927	4,751	4,445
Oyster Bayou	5,075	5,217	4,870	4,868	5,056
Tinsley	6,666	6,311	6,506	6,241	6,053
Other	14	10	19	7	57
Total Gulf Coast region	33,861	33,626	33,239	33,745	32,658
Rocky Mountain region					
Bell Creek	3,209	3,060	3,406	3,571	4,050
Salt Creek ⁽²⁾	—	23	2,228	2,172	2,002
Total Rocky Mountain region	3,209	3,083	5,634	5,743	6,052
Total tertiary oil production	37,070	36,709	38,873	39,488	38,710
Non-tertiary oil and gas production					
Gulf Coast region					
Mississippi	1,342	1,004	867	721	875
Texas	4,333	5,002	4,024	4,617	4,386
Other	495	460	515	483	445
Total Gulf Coast region	6,170	6,466	5,406	5,821	5,706
Rocky Mountain region					
Cedar Creek Anticline	15,067	15,124	14,535	14,302	14,437
Other	1,626	1,475	1,514	1,533	1,485
Total Rocky Mountain region	16,693	16,599	16,049	15,835	15,922
Total non-tertiary production	22,863	23,065	21,455	21,656	21,628
Total production	59,933	59,774	60,328	61,144	60,338

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

(2) Represents production related to the acquisition of a 23% non-operated working interest in Salt Creek Field in Wyoming, which closed on June 30, 2017.

Table of Contents

Denbury Resources Inc.

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

Total Production

Total production during the first quarter of 2018 averaged 60,338 BOE/d, including 38,710 Bbls/d from tertiary properties and 21,628 BOE/d from non-tertiary properties. This total production level represents a slight increase of 405 BOE/d (1%) compared to first quarter of 2017 production levels, and a slight decrease of 806 BOE/d (1%) compared to fourth quarter of 2017 production levels. Production for the first quarter of 2018 was reduced by approximately 800 BOE/d due to extreme cold weather conditions in the Gulf Coast region during January, which caused power outages and freezing, as well as scheduled maintenance at Delhi and Heidelberg fields.

Our production during the three months ended March 31, 2018 was 97% oil, consistent with oil production during the prior-year period.

Tertiary Production

Oil production from our tertiary operations during the first quarter of 2018 decreased 778 Bbls/d (2%) when compared to the fourth quarter of 2017 and increased 1,640 Bbls/d (4%) compared to the same period in 2017. The sequential decrease was primarily due to the extreme cold weather conditions in the Gulf Coast region and scheduled maintenance at Delhi and Heidelberg fields referenced above. The year-over-year increase in production was primarily due to the acquisition of a 23% non-operated working interest in Salt Creek Field during the second quarter of 2017, as well as the CO₂ enhanced oil recovery response from phase 5 development at Bell Creek Field and the redevelopment project at Hastings Field.

Non-Tertiary Production

Production from our non-tertiary operations averaged 21,628 BOE/d during the first quarter of 2018, consistent with production during the fourth quarter of 2017 and a decrease of 1,235 BOE/d (5%) compared to the first quarter of 2017 levels. The year-over-year decrease was primarily due to natural production declines at Cedar Creek Anticline.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three months ended March 31, 2018 increased 28% compared to these revenues for the same period in 2017. 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 March 31, 2018 vs. 2017		
	Increase in Revenues	Percentage Increase in Revenues	
Change in oil and natural gas revenues due to:			
Increase in production	\$1,799	1	%
Increase in commodity prices	72,044	27	%
Total increase in oil and natural gas revenues	\$73,843	28	%

Table of Contents

Denbury Resources Inc.

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

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31, 2018 2017	
Average net realized prices		
Oil price per Bbl	\$64.25	\$50.31
Natural gas price per Mcf	2.44	2.50
Price per BOE	62.61	49.35
Average NYMEX differentials		
Oil per Bbl	\$1.29	\$(1.64)
Natural gas per Mcf	(0.40)	(0.57)

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. Our corporate-wide oil differential during the first quarter of 2018 was \$1.29 per Bbl above NYMEX prices, compared to an average differential of \$1.64 per Bbl below NYMEX in the first quarter of 2017 and \$1.70 per Bbl above NYMEX in the fourth quarter of 2017. Additional information about our oil differentials in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

Our average NYMEX oil differential in the Gulf Coast region was a positive \$2.05 per Bbl and a negative \$1.42 per Bbl during the first quarters of 2018 and 2017, respectively, and a positive \$3.00 per Bbl during the fourth quarter of 2017. 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 average LLS-to-NYMEX differential (on a trade-month basis) averaged a positive \$4.12 per Bbl in the first quarter of 2018, an increase from the positive \$1.58 per Bbl in the first quarter of 2017 and a decrease from the positive \$5.48 per Bbl in the fourth quarter of 2017. During the first quarter of 2018, we sold approximately 65% 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 \$0.06 per Bbl and \$2.09 per Bbl below NYMEX during the first quarters of 2018 and 2017, respectively, and \$0.76 per Bbl below NYMEX during the fourth quarter of 2017. 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 crude oil derivative contracts had on our operating results for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31, 2018 2017	
In thousands		
Payment on settlements of commodity derivatives	\$(33,357)	\$(26,940)
Noncash fair value gains (losses) on commodity derivatives ⁽¹⁾	(15,468)	51,542
Total income (expense)	\$(48,825)	\$24,602

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

Table of Contents

Denbury Resources Inc.

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

In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2019 using both NYMEX and LLS fixed-price swaps, three-way collars and basis swaps. See Note 5, Commodity Derivative Contracts, to the Consolidated Financial Statements for additional details of our outstanding commodity derivative contracts as of March 31, 2018, and Item 3, Quantitative and Qualitative Disclosures about Market Risk below for additional discussion. In addition, the following table summarizes our commodity derivative contracts as of May 7, 2018:

		2Q 2018	2H 2018	1H 2019	2H 2019
WTI	Volumes				
NYMEX	Hedged (Bbls/d)	15,500	15,500	—	—
Fixed-Price Swaps	Swap Price ⁽¹⁾	\$50.13	\$50.13	—	—
WTI	Volumes				
NYMEX	Hedged (Bbls/d)	5,000	5,000	3,500	—
Fixed-Price Swaps	Swap Price ⁽¹⁾	\$56.54	\$56.54	\$59.05	—
Argus LLS	Volumes				
	Hedged (Bbls/d)	5,000	5,000	—	—
Fixed-Price Swaps	Swap Price ⁽¹⁾	\$60.18	\$60.18	—	—
WTI	Volumes				
NYMEX	Hedged (Bbls/d)	15,000	15,000	8,500	12,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price ⁽¹⁾⁽²⁾	\$36.50/\$46.50/\$53.88	\$36.50/\$46.50/\$53.88	\$47.00/\$55.00/\$66.71	\$47.00/\$55.00/\$66.23
WTI	Volumes				
NYMEX	Hedged (Bbls/d)	—	—	3,000	3,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price ⁽¹⁾⁽²⁾	—	—	\$50.00/\$58.00/\$70.41	\$50.00/\$58.00/\$70.41
	Total Volumes Hedged (Bbls/d)	40,500	40,500	15,000	15,000
Argus LLS	Volumes				
	Hedged (Bbls/d)	20,000	—	—	—
Basis Swaps ⁽³⁾	Swap Price ⁽¹⁾	\$4.17	—	—	—

(1) Averages are volume weighted.

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

(3) The basis swap contracts establish a fixed amount for the differential between Argus WTI and Argus LLS prices on a trade-month basis for the periods indicated.

Commodity derivative contracts in place for 2018 and 2019 include fixed-price swaps, three-way collars, and basis swaps. Based on current contracts in place and NYMEX oil futures prices as of May 7, 2018, which average approximately \$69 per Bbl for the remainder of 2018, we currently expect that we would make cash payments of

approximately \$170 million during 2018 upon settlement of these contracts, the amount of which is dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our fixed-price swaps which have weighted average prices of \$51.69 per Bbl and \$60.18 per Bbl for NYMEX and LLS hedges, respectively, weighted average ceiling prices of our three-way collars of \$53.88 per Bbl, as well as changes in the spread between Argus LLS and Argus WTI, which basis swap contracts have weighted average prices of \$4.17 per Bbl. Changes in commodity prices, expiration of contracts, and new commodity contracts entered into cause fluctuations in the estimated fair value of our oil 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.

Production Expenses

Lease Operating Expenses

	Three Months Ended March 31,	
In thousands, except per-BOE data	2018	2017
Total lease operating expenses	\$118,356	\$113,840
Total lease operating expenses per BOE	\$21.80	\$21.11

Table of Contents

Denbury Resources Inc.

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

Total lease operating expenses increased \$4.5 million (4%) on an absolute-dollar basis, or \$0.69 (3%) on a per-BOE basis, during the three months ended March 31, 2018 compared to levels in the same period in 2017. Our lease operating expenses during the comparative first quarter periods were primarily impacted by operating expenses related to our non-operated working interest in Salt Creek Field, which was acquired in June 2017 and has a higher per-BOE operating cost than our corporate average, with the increase partially offset by savings in various cost categories including chemicals and contract labor. Sequentially, lease operating expenses increased \$13.5 million (13%) on an absolute-dollar basis, or \$3.16 (17%) on a per-BOE basis between the fourth quarter of 2017 and the first quarter of 2018, primarily due to a \$7 million reduction for pricing adjustments of certain industrial-sourced CO₂ recorded in the fourth quarter of 2017, as well as higher power and fuel costs and workover activity in the current quarter.

Currently, our CO₂ expense comprises approximately 20% of our typical tertiary lease operating expenses, and for the CO₂ reserves we already own, consists of CO₂ production expenses, and for the CO₂ reserves we do not own, consists of our purchase of CO₂ from royalty and working interest owners and industrial sources. During the first quarters of 2018 and 2017, approximately 54% and 57%, respectively, of the CO₂ utilized in our CO₂ floods consisted of CO₂ owned and produced by us (our net revenue interest). The price we pay others for CO₂ varies by source and is generally indexed to oil prices. When combining the production cost of the CO₂ we own with what we pay third parties for CO₂, our average cost of CO₂ was approximately \$0.39 per Mcf during the first quarter of 2018, including taxes paid on CO₂ production but excluding depletion, depreciation and amortization of capital expended at our CO₂ source fields and industrial sources. This per-Mcf CO₂ cost during the first quarter of 2018 was lower than the \$0.41 per Mcf comparable measure during the first quarter of 2017, but higher than the \$0.28 per Mcf comparable measure during the fourth quarter of 2017 due to the above referenced \$7 million reduction recorded in the fourth quarter of 2017 for pricing adjustments of certain industrial-sourced CO₂.

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. Marketing and plant operating expenses were \$12.4 million and \$14.1 million for the three months ended March 31, 2018 and 2017, respectively.

Taxes Other Than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income increased \$4.9 million (22%) during the three months ended March 31, 2018 compared to the same prior-year period, due primarily to an increase in production taxes resulting from higher oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Three Months Ended March 31,	
In thousands, except per-BOE data and employees	2018	2017
Gross cash compensation and administrative costs	\$57,038	\$66,447
Gross stock-based compensation	3,302	5,388
Operator labor and overhead recovery charges	(31,137)	(31,531)
Capitalized exploration and development costs	(8,971)	(12,063)
Net G&A expense	\$20,232	\$28,241

G&A per BOE		
Net administrative costs	\$3.25	\$4.48
Net stock-based compensation	0.48	0.76
Net G&A expenses	\$3.73	\$5.24
Employees as of March 31	872	1,061

Table of Contents

Denbury Resources Inc.

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

Our gross G&A expenses on an absolute-dollar basis decreased \$11.5 million (16%) during the three months ended March 31, 2018 compared to the same periods in 2017, primarily due to lower employee-related costs such as salaries and long-term incentives during the 2018 period following the August 2017 involuntary workforce reduction.

Net G&A expense on a per-BOE basis decreased 29% during the three months ended March 31, 2018 compared to levels in the same period in 2017 due to the items previously mentioned impacting gross G&A during the 2018 period, partially offset by lower capitalized exploration and development costs.

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	
	March 31,	
In thousands, except per-BOE data and interest rates	2018	2017
Cash interest ⁽¹⁾	\$46,603	\$42,500
Less: interest on Senior Secured Notes and Convertible Senior Notes not reflected as interest for financial reporting purposes ⁽¹⁾	(22,049)	(12,569)
Noncash interest expense	1,137	1,901
Less: capitalized interest	(8,452)	(4,654)
Interest expense, net	\$17,239	\$27,178
Interest expense, net per BOE	\$3.17	\$5.04
Average debt principal outstanding	\$2,742,711	\$2,818,832
Average interest rate ⁽²⁾	6.8	% 6.0 %

Cash interest is presented on an accrual basis, and includes the portion of interest on our 9% Senior Secured Second Lien Notes due 2021 ("2021 Senior Secured Notes"), 2022 Senior Secured Notes, 2023 Convertible Senior Notes and 2024 Convertible Senior Notes versus the GAAP financial statement presentation in which interest on these notes is accounted for as debt and not reflected as interest for financial reporting purposes in accordance with Financial Accounting Standards Board Codification 470-60, Troubled Debt Restructuring by Debtors. See below for further discussion.

(2) Includes commitment fees but excludes debt issue costs.

As reflected in the table above, net interest expense during the three months ended March 31, 2018 decreased \$9.9 million (37%) when compared to the prior-year period due primarily to the series of exchange transactions completed during 2017 and 2018 (see Capital Resources and Liquidity – Recent Debt Reduction Transactions). As more fully described in Note 4, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements, the exchange transactions were accounted for in accordance with Financial Accounting Standards Board Codification 470-60, Troubled Debt Restructuring by Debtors, whereby most of the future interest associated with the 2021 Senior Secured Notes, 2022 Senior Secured Notes, 2023 Convertible Senior Notes and 2024 Convertible Senior Notes was recorded as debt as of the transaction date, which will be reduced as semiannual interest payments are made or in the case of our convertible senior notes, converted into our common stock. Future interest payable recorded as debt totaled \$356.2 million as of March 31, 2018. Therefore, interest expense reflected in our Unaudited Condensed Consolidated

Financial Statements will be significantly lower than the actual cash interest payment. Capitalized interest during the three months ended March 31, 2018 increased \$3.8 million (82%) compared to the same period in 2017, primarily due to an increase in the number of projects that qualify for interest capitalization.

Table of Contents

Denbury Resources Inc.

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

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

In thousands, except per-BOE data	Three Months Ended	
	March 31, 2018	March 31, 2017
Oil and natural gas properties	\$31,871	\$27,818
CO ₂ properties, pipelines, plants and other property and equipment	20,580	23,377
Total DD&A	\$52,451	\$51,195
DD&A per BOE		
Oil and natural gas properties	\$5.87	\$5.16
CO ₂ properties, pipelines, plants and other property and equipment	3.79	4.33
Total DD&A cost per BOE	\$9.66	\$9.49

The increase in our oil and natural gas properties depletion during the three months ended March 31, 2018 when compared to the same period in 2017 was primarily due to an increase in depletable costs associated with our reserves base, partially offset by an increase in proved oil and natural gas reserve quantities. The per-BOE increase was also partially offset by an increase in production volumes during 2018 when compared to production in the 2017 period.

Income Taxes

In thousands, except per-BOE amounts and tax rates	Three Months Ended	
	March 31, 2018	March 31, 2017
Current income tax benefit	\$(1,032)	\$(13,935)
Deferred income tax expense	15,052	34,909
Total income tax expense	\$14,020	\$20,974
Average income tax expense per BOE	\$2.58	\$3.89
Effective tax rate	26.2 %	49.3 %
Total net deferred tax liability	\$213,151	\$328,786

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. Our income taxes are based on an estimated statutory rate of approximately 25% and 38% in 2018 and 2017, respectively. Our effective tax rates for the three months ended March 31, 2018 and 2017 differed from our estimated statutory rates, primarily due to the impact of a tax shortfall on a stock-based compensation deduction (tax deduction less than book expense recognized) of \$1.2 million and \$3.6 million, respectively.

The current income tax benefits for the three months ended March 31, 2018 and 2017, represent the estimated receivable resulting from alternative minimum tax credits.

As of March 31, 2018, we had an estimated \$51.5 million of enhanced oil recovery credits to carry forward related to our tertiary operations, \$21.6 million of research and development credits, and \$20.3 million of alternative minimum tax credits, which under the Tax Cut and Jobs Act, will be fully refundable by 2021. The enhanced oil recovery credits and research and development credits do not begin to expire until 2024 and 2031, respectively.

Table of Contents

Denbury Resources Inc.

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

Per-BOE Data

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

Per-BOE data	Three Months Ended March 31,	
	2018	2017
Oil and natural gas revenues	\$62.61	\$49.35
Payment on settlements of commodity derivatives	(6.14)	(5.00)
Lease operating expenses	(21.80)	(21.11)
Production and ad valorem taxes	(4.61)	(3.86)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.75)	(1.87)
Production netback	28.31	17.51
CO ₂ sales, net of operating and exploration expenses	1.30	0.89
General and administrative expenses	(3.73)	(5.24)
Interest expense, net	(3.17)	(5.04)
Other	0.39	3.33
Changes in assets and liabilities relating to operations	(6.23)	(6.95)
Cash flows from operations	16.87	4.50
DD&A	(9.66)	(9.49)
Deferred income taxes	(2.77)	(6.47)
Noncash fair value gains (losses) on commodity derivatives ⁽¹⁾	(2.85)	9.56
Other noncash items	5.70	5.89
Net income	\$7.29	\$3.99

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

CRITICAL ACCOUNTING POLICIES

For additional discussion of our critical accounting policies, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-K. Any new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements have been included in the notes to the Company's Unaudited Condensed Consolidated Financial Statements contained in this Quarterly Report on Form 10-Q.

FORWARD-LOOKING INFORMATION

The data and/or statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, financial forecasts, future hydrocarbon prices and timing, the degree and length of any price recovery for oil, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to further reduce our debt levels, possible future write-downs of oil

and natural gas reserves, together with assumptions based on current and projected oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on 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, the nature of any future asset sales or the timing or proceeds thereof, estimated timing of commencement

Table of Contents

Denbury Resources Inc.

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

of CO₂ flooding of particular fields or areas, timing of CO₂ injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO₂ reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, potential increases in worldwide tariffs or other trade restrictions, the likelihood, timing and impact of increased interest rates, the impact of regulatory rulings or changes, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, long-term forecasts of production, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions and other variables surrounding our estimated original oil in place, operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "assume," "believe," "may" or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; accuracy of our cost estimates; availability or terms of credit in the commercial banking or other debt markets; 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, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; 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 March 31, 2018, we had \$450.0 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 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 we 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, convertible senior notes, and senior subordinated notes are based on quoted market prices. The following table presents the principal cash flows and fair values of our outstanding debt as of March 31, 2018, and does not reflect the conversions of all of our outstanding 3½% Convertible Senior Notes due 2024 in April 2018:

In thousands	2019	2021	2022	2023	2024	Total	Fair Value
Variable rate debt:							
Senior Secured Bank Credit Facility (weighted average interest rate of 4.5% at March 31, 2018)	\$450,000	\$ —	\$ —	\$ —	\$ —	\$450,000	\$450,000
Fixed rate debt:							
9% Senior Secured Second Lien Notes due 2021	—	614,919	—	—	—	614,919	630,292
9¼% Senior Secured Second Lien Notes due 2022	—	—	455,668	—	—	455,668	463,323
5% Convertible Senior Notes due 2023	—	—	—	59,439	—	59,439	53,335
3½% Convertible Senior Notes due 2024	—	—	—	—	84,650	84,650	104,340
6 % Senior Subordinated Notes due 2021	—	203,545	—	—	—	203,545	171,487
5½% Senior Subordinated Notes due 2022	—	—	314,662	—	—	314,662	249,370
4 % Senior Subordinated Notes due 2023	—	—	—	307,978	—	307,978	228,674

See Note 4, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements for details regarding our long-term debt.

Commodity Derivative Contracts

We enter into oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil 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, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices. In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2019 using both NYMEX and LLS fixed-price swaps, three-way collars and basis swaps. Depending on market conditions, we may continue to add to our existing 2019 hedges. 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

Table of Contents

Denbury Resources Inc.

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 instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At March 31, 2018, our commodity derivative contracts were recorded at their fair value, which was a net liability of \$114.5 million, a \$15.4 million increase from the \$99.1 million net liability recorded at December 31, 2017. This change is primarily related to the expiration of commodity derivative contracts during the three months ended March 31, 2018, new commodity derivative contracts entered into during 2018 for future periods, and to the changes in oil futures prices between December 31, 2017 and March 31, 2018.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of March 31, 2018, 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 March 31, 2018	\$(111,901)
10% increase in prices	(187,612)
10% decrease in prices	(30,249)

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 production to which those commodity derivative contracts relate.

Table of Contents

Denbury Resources Inc.

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 March 31, 2018, 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, that it is 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 first quarter of fiscal 2018, 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.

Table of Contents

Denbury Resources Inc.

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.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC. The helium supply contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after startup of the Riley Ridge gas processing facility, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are specified in the contract at up to \$8.0 million per contract year and are capped at an aggregate of \$46.0 million over the term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium under the helium supply contract. APMTG Helium, LLC filed a case in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, claiming multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company's position is that our contractual obligations are excused by virtue of events that fall within the force majeure provisions in the helium supply contract. The evidentiary phase of the trial closed on November 29, 2017. The parties submitted written closing briefs and rebuttal briefs to the District Court during February and April of 2018. We currently expect a ruling from the District Court to be made in the second or third quarter of 2018. The Company plans to continue to vigorously defend its position, but we are unable to predict at this time the outcome of this dispute.

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.

Table of Contents

Denbury Resources Inc.

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

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the first quarter of 2018:

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⁾
January 2018	—	\$	—	\$ 210.1
February 2018	1,752	2.27	—	210.1
March 2018	165,097	2.73	—	210.1
Total	166,849		—	

(1) Shares purchased during the first quarter of 2018 were made in connection with the surrender of shares by our employees to satisfy their tax withholding requirements related to the vesting of restricted and performance shares.

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. This program has (2) effectively been suspended and we do not anticipate repurchasing shares of our common stock in the near future. 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.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Table of Contents

Denbury Resources Inc.

Item 6. Exhibits

Exhibit No.	Exhibit
10(a)*	<u>Denbury Resources Inc. Severance Protection Plan, as amended and restated effective as of March 29, 2018.</u>
10(b)*	<u>Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of March 29, 2018.</u>
10(c)*	<u>2018 Form of TSR Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.</u>
10(d)*	<u>2018 Form of TSR Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.</u>
10(e)*	<u>2018 Form of Debt-Adjusted Reserves Growth Per Share Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.</u>
10(f)*	<u>2018 Form of Debt-Adjusted Reserves Growth Per Share Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.</u>
31(a)*	<u>Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
31(b)*	<u>Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u>
32*	<u>Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u>
101*	Interactive Data Files.

*Included herewith.

Table of Contents

Denbury Resources Inc.

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.

May 10, 2018 /s/ Mark C. Allen
Mark C. Allen
Executive Vice President and Chief Financial Officer

May 10, 2018 /s/ Alan Rhoades
Alan Rhoades
Vice President and Chief Accounting Officer