DENBURY RESOURCES INC
Form 10-Q
August 08, 2017
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

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

For the quarterly period ended June 30, 2017
OR

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

For the transition period from _______ to ________

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

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

| | |
|---|---|
| 5320 Legacy Drive,<br>Plano, TX | 75024 |
| (Address of principal executive offices) | (Zip Code) |

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 þ | Accelerated filer o | Non-accelerated filer o<br>(Do not check if a smaller reporting company) | Smaller reporting company o | Emerging growth company o |

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. o

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

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

| Class | Outstanding at July 31, 2017 |
|---|---|
| Common Stock, $.001 par value | 403,045,927 |

Denbury Resources Inc.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| Assets | | |
| Current assets | | |
| Cash and cash equivalents | $3,508 | $1,606 |
| Accrued production receivable | 103,822 | 124,936 |
| Trade and other receivables, net | 60,393 | 43,900 |
| Derivative assets | 3,572 | — |
| Other current assets | 14,934 | 10,684 |
| Total current assets | 186,229 | 181,126 |
| Property and equipment | | |
| Oil and natural gas properties (using full cost accounting) | | |
| Proved properties | 10,631,368 | 10,419,827 |
| Unevaluated properties | 954,189 | 927,819 |
| $CO_2$ properties | 1,188,555 | 1,188,467 |
| Pipelines and plants | 2,285,841 | 2,285,812 |
| Other property and equipment | 371,886 | 378,776 |
| Less accumulated depletion, depreciation, amortization and impairment | (11,302,655) | (11,212,327) |
| Net property and equipment | 4,129,184 | 3,988,374 |
| Derivative assets | 1,237 | — |
| Other assets | 108,691 | 105,078 |
| Total assets | $4,425,341 | $4,274,578 |
| Liabilities and Stockholders' Equity | | |
| Current liabilities | | |
| Accounts payable and accrued liabilities | $177,950 | $200,266 |
| Oil and gas production payable | 67,933 | 80,585 |
| Derivative liabilities | — | 69,279 |
| Current maturities of long-term debt (including future interest payable of $50,490 and $50,349, respectively – see Note 3) | 83,458 | 83,366 |
| Total current liabilities | 329,341 | 433,496 |
| Long-term liabilities | | |
| Long-term debt, net of current portion (including future interest payable of $153,196 and $178,476, respectively – see Note 3) | 3,060,048 | 2,909,732 |
| Asset retirement obligations | 154,454 | 146,807 |
| Derivative liabilities | 407 | — |
| Deferred tax liabilities, net | 345,025 | 293,878 |
| Other liabilities | 21,867 | 22,217 |
| Total long-term liabilities | 3,581,801 | 3,372,634 |
| Commitments and contingencies (Note 7) | | |
| Stockholders' equity | | |
| Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding | — | — |

| | | |
|---|---|---|
| Common stock, $.001 par value, 600,000,000 shares authorized; 403,305,493 and 402,334,655 shares issued, respectively | 403 | 402 |
| Paid-in capital in excess of par | 2,546,102 | 2,534,670 |
| Accumulated deficit | (1,983,056 ) | (2,018,989 ) |
| Treasury stock, at cost, 4,405,555 and 3,906,877 shares, respectively | (49,250 ) | (47,635 ) |
| Total stockholders' equity | 514,199 | 468,448 |
| Total liabilities and stockholders' equity | $4,425,341 | $4,274,578 |

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Revenues and other income | | | | |
| Oil, natural gas, and related product sales | $250,880 | $246,668 | $517,058 | $434,471 |
| $CO_2$ sales and transportation fees | 6,555 | 6,622 | 11,943 | 12,894 |
| Interest income and other income | 3,749 | 1,858 | 7,637 | 2,627 |
| Total revenues and other income | 261,184 | 255,148 | 536,638 | 449,992 |
| Expenses | | | | |
| Lease operating expenses | 111,318 | 100,019 | 225,158 | 202,466 |
| Marketing and plant operating expenses | 13,877 | 12,999 | 27,942 | 26,193 |
| $CO_2$ discovery and operating expenses | 513 | 1,071 | 1,106 | 1,678 |
| Taxes other than income | 20,175 | 19,504 | 42,615 | 39,596 |
| General and administrative expenses | 25,789 | 22,545 | 54,030 | 56,446 |
| Interest, net of amounts capitalized of $8,147, $6,289, $12,801 and $12,069, respectively | 24,061 | 36,058 | 51,239 | 78,229 |
| Depletion, depreciation, and amortization | 51,152 | 66,541 | 102,347 | 143,907 |
| Commodity derivatives expense (income) | (10,373) | 98,209 | (34,975) | 121,035 |
| Gain on debt extinguishment | — | (12,278) | — | (107,269) |
| Write-down of oil and natural gas properties | — | 479,400 | — | 735,400 |
| Other expenses | — | 34,688 | — | 36,232 |
| Total expenses | 236,512 | 858,756 | 469,462 | 1,333,913 |
| Income (loss) before income taxes | 24,672 | (603,608) | 67,176 | (883,921) |
| Income tax provision (benefit) | 10,273 | (222,940) | 31,247 | (318,060) |
| Net income (loss) | $14,399 | $(380,668) | $35,929 | $(565,861) |
| | | | | |
| Net income (loss) per common share | | | | |
| Basic | $0.04 | $(1.03) | $0.09 | $(1.58) |
| Diluted | $0.04 | $(1.03) | $0.09 | $(1.58) |
| | | | | |
| Weighted average common shares outstanding | | | | |
| Basic | 389,904 | 370,566 | 389,652 | 358,901 |
| Diluted | 391,827 | 370,566 | 392,414 | 358,901 |

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

| | Six Months Ended June 30, 2017 | 2016 |
|---|---|---|
| Cash flows from operating activities | | |
| Net income (loss) | $35,929 | $(565,861) |
| Adjustments to reconcile net income (loss) to cash flows from operating activities | | |
| Depletion, depreciation, and amortization | 102,347 | 143,907 |
| Write-down of oil and natural gas properties | — | 735,400 |
| Deferred income taxes | 51,147 | (318,055) |
| Stock-based compensation | 8,941 | 4,122 |
| Commodity derivatives expense (income) | (34,975) | 121,035 |
| Receipt (payment) on settlements of commodity derivatives | (38,707) | 124,253 |
| Gain on debt extinguishment | — | (107,269) |
| Debt issuance costs and discounts | 3,344 | 14,072 |
| Other, net | (1,006) | (1,743) |
| Changes in assets and liabilities, net of effects from acquisitions | | |
| Accrued production receivable | 21,114 | (20,060) |
| Trade and other receivables | (17,916) | 17,568 |
| Other current and long-term assets | (10,225) | (7,974) |
| Accounts payable and accrued liabilities | (26,611) | (71,830) |
| Oil and natural gas production payable | (12,652) | (3,624) |
| Other liabilities | (3,522) | (997) |
| Net cash provided by operating activities | 77,208 | 62,944 |
| Cash flows from investing activities | | |
| Oil and natural gas capital expenditures | (129,884) | (126,302) |
| Acquisitions of oil and natural gas properties | (89,208) | (904) |
| Other | (2,058) | (314) |
| Net cash used in investing activities | (221,150) | (127,520) |
| Cash flows from financing activities | | |
| Bank repayments | (796,000) | (994,000) |
| Bank borrowings | 985,000 | 1,139,000 |
| Interest payments on senior secured notes treated as a reduction of debt | (25,139) | — |
| Repurchases of senior subordinated notes | — | (55,521) |
| Pipeline financing and capital lease debt repayments | (13,728) | (14,336) |
| Other | (4,289) | (10,834) |
| Net cash provided by financing activities | 145,844 | 64,309 |
| Net increase (decrease) in cash and cash equivalents | 1,902 | (267) |
| Cash and cash equivalents at beginning of period | 1,606 | 2,812 |
| Cash and cash equivalents at end of period | $3,508 | $2,545 |

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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Note 1. Basis of Presentation

Organization and Nature of Operations

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

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2016 (the "Form 10-K"). Unless indicated otherwise or the context requires, the terms "we," "our," "us," "Company" or "Denbury," refer to Denbury Resources Inc. and its subsidiaries.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end, and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of June 30, 2017, our consolidated results of operations for the three and six months ended June 30, 2017 and 2016, and our consolidated cash flows for the six months ended June 30, 2017 and 2016.

Reclassifications

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

Net Income (Loss) per Common Share

Basic net income (loss) per common share is computed by dividing the net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of nonvested restricted stock and nonvested performance-based equity awards. For the three and six months ended June 30, 2017 and 2016, there were no adjustments to net income (loss) for purposes of calculating basic and diluted net income (loss) per common share.

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

| | Three Months Ended | Six Months Ended |
|---|---|---|

| | June 30, | | June 30, | |
|---|---|---|---|---|
| In thousands | 2017 | 2016 | 2017 | 2016 |
| Basic weighted average common shares outstanding | 389,904 | 370,566 | 389,652 | 358,901 |
| Potentially dilutive securities | | | | |
| Restricted stock and performance-based equity awards | 1,923 | — | 2,762 | — |
| Diluted weighted average common shares outstanding | 391,827 | 370,566 | 392,414 | 358,901 |

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income (loss) per common share (although time-vesting restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the three and six months ended June 30, 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.

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

| | Three Months Ended | | Six Months Ended | |
|---|---|---|---|---|
| | June 30, | | June 30, | |
| In thousands | 2017 | 2016 | 2017 | 2016 |
| Stock appreciation rights | 4,785 | 6,265 | 4,914 | 6,839 |
| Restricted stock and performance-based equity awards | 7,655 | 4,374 | 4,442 | 4,491 |

2016 Write-Down of Oil and Natural Gas Properties

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. The falling prices in 2016, relative to 2015 prices, led to our recognizing full cost pool ceiling test write-downs of $479.4 million and $256.0 million during the three months ended June 30 and March 31, 2016, respectively. We did not record a ceiling test write-down during the three or six months ended June 30, 2017.

Recent Accounting Pronouncements

Business Combinations. In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-01, Business Combinations: Clarifying the Definition of a Business ("ASU 2017-01"). ASU 2017-01 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. Effective January 1, 2017, we adopted ASU 2017-01. See Note 2, Asset Acquisition, for discussion of the impact ASU 2017-01 had on our current period consolidated financial statements.

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

Revenue Recognition. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). ASU 2014-09 amends the guidance for revenue recognition to replace numerous, industry-specific requirements. The core principle of the ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU implements a five-step process for customer contract revenue recognition that focuses on transfer of control, as opposed to transfer of risk and rewards. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers ("ASU 2015-14") which amends ASU 2014-09 and delays the effective date for public companies, such that the amendments in the ASU are effective for reporting periods beginning after December 15, 2017, and early adoption will be permitted for periods beginning after December 15, 2016. In March, April and May 2016, the FASB issued four additional ASUs which primarily clarified the implementation guidance on principal versus agent considerations, performance obligations and licensing, collectibility, presentation of sales taxes and other similar taxes collected from customers, and non-cash consideration. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. We expect to adopt this standard using the modified retrospective method upon its effective date. Management is currently in the process of reviewing our various revenue contracts to determine the impact of adoption of this new guidance and has not yet determined the effect this standard will have on our consolidated financial statements.

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Denbury Resources Inc.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 2. Asset Acquisition

On June 30, 2017, we acquired a 23% non-operated working interest in Salt Creek Field in Wyoming for cash consideration of approximately $71.5 million, before customary closing adjustments. The transaction was accounted for as an asset acquisition in accordance with ASU 2017-01. Therefore, the acquired interests were recorded based upon the cash consideration paid, with all value assigned to proved oil and natural gas properties.

Note 3. Long-Term Debt

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

| In thousands | June 30, 2017 | December 31, 2016 |
|---|---|---|
| Senior Secured Bank Credit Agreement | $490,000 | $301,000 |
| 9% Senior Secured Second Lien Notes due 2021 | 614,919 | 614,919 |
| 6 % Senior Subordinated Notes due 2021 | 215,144 | 215,144 |
| 5½% Senior Subordinated Notes due 2022 | 772,912 | 772,912 |
| 4 % Senior Subordinated Notes due 2023 | 622,297 | 622,297 |
| Other Subordinated Notes, including premium of $2 and $3, respectively | 2,252 | 2,253 |
| Pipeline financings | 197,726 | 202,671 |
| Capital lease obligations | 38,829 | 48,718 |
| Total debt principal balance | 2,954,079 | 2,779,914 |
| Future interest payable on 9% Senior Secured Second Lien Notes due 2021 (1) | 203,686 | 228,825 |
| Issuance costs on senior secured second lien and senior subordinated notes | (14,259) | (15,641) |
| Total debt, net of debt issuance costs | 3,143,506 | 2,993,098 |
| Less: current maturities of long-term debt (1) | (83,458) | (83,366) |
| Long-term debt and capital lease obligations | $3,060,048 | $2,909,732 |

(1) Future interest payable on our 9% Senior Secured Second Lien Notes due 2021 (the "2021 Senior Secured Notes") represents most of the interest due over the term of this obligation, which has been accounted for as debt in accordance with Financial Accounting Standards Board Codification ("FASC") 470-60, Troubled Debt Restructuring by Debtors. Our current maturities of long-term debt as of June 30, 2017 include $50.5 million of future interest payable related to the 2021 Senior Secured Notes that is due within the next twelve months.

The ultimate parent company in our corporate structure, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding 2021 Senior Secured Notes and our senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI, and the guarantees of the notes are full and unconditional and joint and several; any subsidiaries of DRI that are not subsidiary guarantors of such notes are minor subsidiaries.

Senior Secured Bank Credit Facility

In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the "Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2019. In May 2017, as part of our semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit

Agreement were reaffirmed at $1.05 billion, with the next such redetermination scheduled for November 2017. 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 4.2% as of June 30, 2017. We incur a commitment fee of 0.50% on the undrawn portion of the aggregate lender commitments under the Bank Credit Agreement.

In conjunction with the May 2017 borrowing base redetermination, we amended certain terms and financial performance covenants through the remaining term of the Bank Credit Agreement in order to provide more flexibility in managing the credit extended by our lenders. The amendments to the Bank Credit Agreement included the following:

- Eliminating the consolidated total net debt to consolidated EBITDAX covenants that were scheduled to go into effect starting in 2018 through the remaining term of the facility;
- Extending the existing consolidated senior secured debt to consolidated EBITDAX covenant through the remaining term of the facility, 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;
- Extending the existing minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0 through the remaining term of the facility, as it previously would have expired after the fourth quarter of 2017; and
- Increasing the applicable margin for ABR Loans and LIBOR Loans by 50 basis points such that the margin for ABR Loans now ranges from 1.5% to 2.5% per annum and the margin for LIBOR Loans now ranges from 2.5% to 3.5% per annum.

The requirement to maintain a current ratio of 1.0 to 1.0 was not amended, and so remains in place. Also, incurrence of additional debt (separate from debt under the credit facility) in connection with various events remains subject to a Total Leverage Test unless the consolidated total net debt to EBITDAX ratio is reduced on a pro forma basis by the event. All of the above descriptions of our Bank Credit Agreement and the amendments thereto are qualified by the express language and defined terms contained in the Bank Credit Agreement and the Fourth Amendment to the Bank Credit Agreement dated May 3, 2017, each of which are filed as exhibits to our periodic reports filed with the SEC.

2016 Senior Subordinated Notes Exchange

During May 2016, in privately negotiated transactions, we exchanged a total of $1,057.8 million of our existing senior subordinated notes for $614.9 million principal amount of our 2021 Senior Secured Notes plus 40.7 million shares of Denbury common stock, resulting in a net reduction from these exchanges of $442.9 million in our debt principal. The exchanged notes consisted of $175.1 million principal amount of our 6 % Senior Subordinated Notes due 2021 (“2021 Notes”), $411.0 million principal amount of our 5½% Senior Subordinated Notes due 2022 (“2022 Notes”), and $471.7 million principal amount of our 4 % Senior Subordinated Notes due 2023 (“2023 Notes”). As a result of this debt exchange, we recognized a gain of $12.3 million during the three months ended June 30, 2016, which is included in “Gain on debt extinguishment” in the accompanying Consolidated Statements of Operations.

2016 Repurchases of Senior Subordinated Notes

During the first quarter of 2016, we repurchased a total of $152.3 million of our outstanding long-term indebtedness, consisting of $4.0 million principal amount of our 2021 Notes, $42.3 million principal amount of our 2022 Notes, and $106.0 million principal amount of our 2023 Notes in open-market transactions for a total purchase price of $55.5 million, excluding accrued interest. In connection with these transactions, we recognized a $95.0 million gain on extinguishment, net of unamortized debt issuance costs written off, during the three months ended March 31, 2016. As of August 7, 2017, under the Bank Credit Agreement, up to an additional $148.3 million may be spent on repurchases or other redemptions of our senior subordinated notes.

Note 4. Income Taxes

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. As of June 30, 2017, we had $36.5 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of falling commodity prices, combined with a new tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company’s utilization of certain deductions, including our net operating loss carryforwards, we recognized tax valuation allowances totaling $36.5 million during 2015 and 2016, which reduced the carrying value of these deferred tax assets to zero as of December 31, 2016. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

As of June 30, 2017, we had an unrecognized tax benefit of $5.4 million related to an uncertain tax position. The unrecognized tax benefit was recorded during 2015 as a direct reduction of the associated deferred tax asset and, if recognized, would not materially affect our annual effective tax rate. The tax benefit from an uncertain tax position will only be recognized if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. We currently do not expect a material change to the uncertain tax position within the next 12 months. Our policy is to recognize penalties and interest related to uncertain tax positions in income tax expense; however, no such amounts were accrued related to the uncertain tax position as of June 30, 2017.

Note 5. Commodity Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; therefore, the changes in the fair values of these instruments are recognized in income in the period of change.  These fair value changes, along with the settlements of expired contracts, are shown under “Commodity derivatives expense (income)” in our Unaudited Condensed Consolidated Statements of Operations.

Historically, we have entered into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. The production that we hedge has varied from year to year depending on our levels of debt, financial strength and expectation of future commodity prices.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis.  We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement (or affiliates of such lenders). As of June 30, 2017, 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.

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

The following table summarizes our commodity derivative contracts as of June 30, 2017, none of which are classified as hedging instruments in accordance with the FASC Derivatives and Hedging topic:

| Months | Index Price | Volume (Barrels per day) | Contract Prices ($/Bbl) | | | | |
|---|---|---|---|---|---|---|---|
| | | | Range [1] | Weighted Average Price | | | |
| | | | | Swap | Sold Put | Floor | Ceiling |
| Oil Contracts: | | | | | | | |
| 2017 Three-Way Collars [2] | | | | | | | |
| July – Sept | NYMEX | 14,500 | $40.00–70.25 | $— | $30.00 | $40.00 | $69.09 |
| July – Sept | LLS | 2,000 | 41.00–69.25 | — | 31.00 | 41.00 | 69.25 |
| Oct – Dec | NYMEX | 11,000 | 40.00–70.20 | — | 30.00 | 40.00 | 69.67 |
| Oct – Dec | LLS | 1,000 | 41.00–70.25 | — | 31.00 | 41.00 | 70.25 |
| 2017 Collars | | | | | | | |
| Oct – Dec | NYMEX | 1,000 | $40.00–70.00 | $— | $— | $40.00 | $70.00 |
| 2018 Fixed-Price Swaps | | | | | | | |
| Jan – Dec | NYMEX | 3,000 | $50.12–50.25 | $50.20 | $— | $— | $— |
| 2018 Three-Way Collars [2] | | | | | | | |
| Jan – Dec | NYMEX | 6,000 | $45.00–56.60 | $— | $36.25 | $46.25 | $55.08 |

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

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

Note 6. Fair Value Measurements

The FASC Fair Value Measurement topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the “exit price”). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the income approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

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

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil derivatives that are based on NYMEX pricing and fixed-price swaps that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). Our costless collars and the sold put features of our three-way collars are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contractual prices for the underlying instruments, maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

- Level 3 – Pricing inputs include significant inputs that are generally less observable. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At June 30, 2017, instruments in this category include 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 are developed using a benchmark, which is considered a significant unobservable input. An increase or decrease of 100 basis points in the implied volatility inputs utilized in our fair value measurement would result in a change of approximately $9 thousand in the fair value of these instruments as of June 30, 2017.

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

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

| | Fair Value Measurements Using: | | | |
|---|---|---|---|---|
| In thousands | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| June 30, 2017 | | | | |
| Assets | | | | |
| Oil derivative contracts – current | $ — | $ 3,473 | $ 99 | $ 3,572 |
| Oil derivative contracts – long-term | — | 1,237 | — | 1,237 |
| Total Assets | $ — | $ 4,710 | $ 99 | $ 4,809 |
| Liabilities | | | | |
| Oil derivative contracts – long-term | $ — | $ (407) | $ — | $ (407) |
| Total Liabilities | $ — | $ (407) | $ — | $ (407) |
| December 31, 2016 | | | | |
| Liabilities | | | | |
| Oil derivative contracts – current | $ — | $ (68,753) | $ (526) | $ (69,279) |
| Total Liabilities | $ — | $ (68,753) | $ (526) | $ (69,279) |

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.

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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 and six months ended June 30, 2017 and 2016:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| In thousands | 2017 | 2016 | 2017 | 2016 |
| Fair value of Level 3 instruments, beginning of period | $91 | $23,040 | $(526) | $52,834 |
| Fair value gains (losses) on commodity derivatives | 8 | (4,818 ) | 625 | (4,536 ) |
| Receipts on settlements of commodity derivatives | — | (17,982 ) | — | (48,058 ) |
| Fair value of Level 3 instruments, end of period | $99 | $240 | $99 | $240 |
| The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets or liabilities still held at the reporting date | $8 | $(3,857 ) | $245 | $(3,870 ) |

We utilize an income approach to value our Level 3 costless collars and three-way collars. We obtain and ensure the appropriateness of the significant inputs to the calculation, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. The following table details fair value inputs related to implied volatilities utilized in the valuation of our Level 3 oil derivative contracts:

| | Fair Value at 6/30/2017 (in thousands) | Valuation Technique | Unobservable Input | Volatility Range |
|---|---|---|---|---|
| Oil derivative contracts | $ 99 | Discounted cash flow / Black-Scholes | Volatility of Light Louisiana Sweet for settlement periods beginning after June 30, 2017 | 18.4% – 32.6% |

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 2021 Senior Secured 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 June 30, 2017 and December 31, 2016, excluding pipeline financing and capital lease obligations, was $1,973.8 million and $2,327.8 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

Commitments

The Company has a $CO_2$ offtake agreement with Mississippi Power Company ("MSPC"), providing for our purchase of $CO_2$ generated as a byproduct of the gasification portion of their Kemper County energy facility. In June 2017, MSPC announced the immediate suspension of startup and operations activities of the lignite coal gasification portion of the Kemper County energy facility, resulting in no further sale of $CO_2$ to us while operation of the lignite coal gasification portion of the facility is suspended.

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, we assumed a 20-year helium supply contract under which we agreed to supply to a third-party purchaser the helium separated from the full well stream by operation of the gas processing facility. 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 capped at $8.0 million per contract year and are capped at an aggregate of $46.0 million over the remaining term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium to the third-party purchaser under the helium supply contract. In a case originally filed in November 2014 by APMTG Helium, LLC, the third-party helium purchaser, after a week of trial during February 2017 on the third-party purchaser’s claim for multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract, and on our claim that the contractual obligation is excused by virtue of events that fall within the force majeure provisions in the helium supply contract, the trial was stayed until November 2017. The Company plans to continue to vigorously defend its position and pursue its claim, but we are unable to predict at this time the outcome of this dispute.

Note 8. Additional Balance Sheet Details

Trade and Other Receivables, Net

| In thousands | June 30, 2017 | December 31, 2016 |
|---|---|---|
| Trade accounts receivable, net | $17,211 | $ 20,084 |
| Federal income tax receivable | 11,271 | — |
| Other receivables | 31,911 | 23,816 |
| Total | $60,393 | $ 43,900 |

Note 9. Subsequent Events

Employee Equity Award Grants

On July 11, 2017, the Compensation Committee of our Board of Directors granted customary long-term equity incentive awards covering 4,656,823 shares of restricted stock to our employees under our 2004 Omnibus Stock and

Incentive Plan. The closing price of Denbury's common stock on July 11, 2017 was $1.52 per share. The awards generally vest one-third per year over a three-year period.

Assets Held for Sale

During July 2017, we signed an exclusive listing agreement to begin actively marketing for sale certain non-productive surface acreage ideally suited for commercial development in the Houston area, which we currently anticipate selling during the next 12 months, although no such sale is assured. This acreage was acquired through a combination of certain producing oilfield acquisitions and separate land purchases, and as of June 30, 2017, the carrying value of the land was $33.1 million, which is included in "Other property and equipment" on our Unaudited Condensed Consolidated Balance Sheets.

## 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, 2016 (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 $CO_2$ 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 are highly impacted by worldwide oil supply and demand and have historically been subject to significant price changes over short periods of time. Over the last few years, we have been in a period of lower oil prices during which oil prices have generally averaged in the $30-$50 per Bbl range, which is roughly 50% lower than the oil price range over the 2011 through 2014 period. As a result of the lower oil price environment and its impact on our business, our focus has primarily been on preservation of cash and liquidity, together with cost reductions, rather than concentration on expansion and growth.

Our realized oil price, excluding the impact of derivative contract settlements, averaged $47.16 per Bbl in the second quarter of 2017, a decline of 6% from realized prices in the first quarter of 2017. Our realized oil price, including the impact from derivative settlements, was $44.92 in the second quarter of 2017, roughly flat when compared to the first quarter of 2017, and 15% lower when compared to the second quarter of 2016. Early in 2017, when we set our development capital budget at $300 million, the forecasted oil price for 2017 was projected to average in the low-to-mid $50's per Bbl. As prices during the first half of 2017 have been lower than originally projected, and to protect our cash and liquidity, we have reduced our 2017 estimated development capital spending by $50 million, from $300 million to $250 million, excluding acquisitions and capitalized interest. Despite this reduction in our capital budget, we currently anticipate our 2017 production (before acquisitions) meeting or exceeding the midpoint of our original production guidance and our 2016 exit rate of roughly 60,000 BOE/d, primarily due to the successful execution of our capital projects in the first half of this year and the low decline rates of our oil-producing assets.

Operating Highlights. We recognized net income of $14.4 million, or $0.04 per diluted common share, during the second quarter of 2017, compared to a net loss of $380.7 million, or $1.03 per diluted common share, during the second quarter of 2016. The significant swing from a net loss in the second quarter of 2016 to net income in the second quarter of 2017 was primarily due to the prior year's second quarter including a $479.4 million ($299.4 million net of tax) full cost pool ceiling test write-down of our oil and natural gas properties and a $27.5 million cash payment to Evolution Petroleum Corporation ("Evolution"), offset in part by a $12.3 million gain on extinguishment of debt. Additional factors leading to the 2017 period's improved results included (1) a $108.6 million improvement in commodity derivatives income, consisting of positive impacts from noncash fair value adjustments of $172.4 million, partially offset by negative impacts from reduced cash receipts from settlements of commodity derivative contracts between the two periods, (2) a $15.4 million (23%) decrease in depletion, depreciation, and amortization, and (3) a $12.0 million (33%) decrease in interest expense, partially offset by a $11.3 million (11%) increase in lease operating expenses.

We generated $52.9 million of cash flows from operating activities in the second quarter of 2017, a decrease of $8.0 million from the second quarter of 2016 levels. The decrease in cash flows from operations was due primarily to less favorable commodity hedge positions in the current year period, which resulted in a $63.8 million decline in commodity derivative receipts ($11.8 million of net payments during the second quarter of 2017 compared to $52.0 million of net receipts during the second quarter of 2016) and an $11.3 million increase in lease operating expenses, partially offset by the prior year’s second quarter results including a $27.5 million cash payment to Evolution, a $12.0 million decrease in interest expense and lower comparative working capital outflows ($12.3 million during the second quarter of 2017 compared to $32.1 million during the second quarter of 2016).

Second Quarter 2017 Salt Creek Field Acquisition. On June 30, 2017, we acquired a 23% non-operated working interest in Salt Creek Field in Wyoming for cash consideration of approximately $71.5 million (before customary closing adjustments). Salt Creek Field is an ongoing $CO_2$ flood, and current tertiary production from the field is estimated at slightly above 2,000 Bbls/d, net to our interest. Production from Salt Creek Field is expected to increase over the next several years with minimal capital spending. As of June 30, 2017, net to our interest, the field had estimated proved oil reserves of approximately 17 MMBbls, including proved developed reserves of approximately 14 MMBbls.

First Quarter 2017 West Yellow Creek Field Acquisition. In March 2017, we acquired an approximate 48% non-operated working interest in West Yellow Creek Field in Mississippi for approximately $16 million (before closing adjustments). West Yellow Creek Field currently has approximately 2 MMBbls of proved oil reserves, net to our interest, but minimal production, as the operator is in the process of completing the conversion of the field to a $CO_2$ EOR flood and has invested significant capital in that development. Having available $CO_2$ was a primary factor in being able to enter into this transaction, in which we will sell $CO_2$ to the operator. Based on current plans, we expect capital expenditures on this development to be less than $10 million in 2017, with first tertiary production expected from the field in late 2017 or early 2018.

## CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability of borrowing capacity under our senior secured bank credit facility. For the first six months of 2017, we generated cash flows from operations of $77.2 million, $14.3 million higher than cash flows generated from operations in the first six months of 2016. Our cash flows for the six months ended June 30, 2017 were negatively impacted by $38.7 million in payments on settlements of commodity derivatives, which primarily consisted of fixed-price swaps with a weighted-average price of approximately $44 per barrel. We currently anticipate that our cash flows from operations will be higher in the second half of 2017 than in the first half of 2017, assuming oil prices remain near current levels, in the upper $40's per Bbl, with minimal impact from our hedging positions. As of August 7, 2017, we have a combination of fixed-price swaps, collars and three-way collars in place for the second half of 2017 on approximately one-third of our anticipated oil production. The fixed-price swaps have a weighted average price of approximately $50 per Bbl, and collar structures have average per-barrel ceiling prices in the high $60's, floor prices in the low $40's, and sold puts of approximately $30.

Outstanding borrowings under our senior secured bank credit facility were $490.0 million as of June 30, 2017, compared to $301.0 million as of December 31, 2016. This $189.0 million increase is primarily due to our capital expenditure levels, which includes $89.2 million of oil and natural gas property acquisitions in the first six months of 2017, $49.8 million of cash outflows for working capital changes, and repayments of other non-bank debt of $38.9 million. Assuming oil prices remain around current levels in the upper $40's per Bbl for the remainder of the year, we anticipate that our cash flows from operations will be higher in the second half of 2017, and therefore we expect our senior secured bank credit facility borrowings will decrease through the second half of 2017, ending the year in a projected range of between $425 million and $475 million.

We have been proactive in adjusting our capital spending in connection with the lower oil price environment over the past several years, and as discussed in the Overview above, we recently adjusted our anticipated full-year 2017 capital budget, excluding acquisitions and capitalized interest, from $300 million to $250 million. Based on our current production forecast and hedges currently in place, using expected average oil prices in the upper $40's per barrel for the remainder of 2017, we currently expect that our operations would fund all but a modest amount of this capital spending, after consideration of interest accounted for as debt but excluding acquisitions and capitalized interest (see Capital Spending below for further discussion). To the extent our cash flows from operations is less than our capital spending, we currently plan to fund those expenditures in the near term with incremental borrowings under our bank credit facility. If oil prices were to decrease or changes in operating results were to cause a reduction in anticipated 2017 cash flows significantly below our currently forecasted operating cash flows, we could further reduce our capital expenditures, as only a small portion of our planned capital spending is subject to contracts that cannot be terminated. Any sizeable reduction in our capital spending could negatively impact our production levels in future periods.

The preservation of cash and liquidity remains a significant priority for us in the current oil price environment. As of June 30, 2017, we had $490.0 million drawn on our $1.05 billion senior secured bank credit facility and $62.2 million of outstanding letters of credit. Based on current expectations and assuming oil prices remain in the upper $40's per Bbl for the remainder of 2017, we expect our available borrowing capacity under our senior secured bank credit facility to increase to between $500 and $550 million at the end of 2017. This liquidity, coupled with continuing cost savings and liquidity preservation measures, should be sufficient to cover any foreseeable cash flow shortfall between our cash flows from operations and capital spending. The

Company may also raise funds through asset sales, issuance of second lien notes or other notes and/or equity, which would enable us to reduce our outstanding borrowings on the credit facility and further increase our available liquidity.

Since we do not expect oil prices to return in the foreseeable future to recent historical highs of 2014, we have adjusted, and must continue to adjust, our business through efficiencies and cost reductions to compete in an oil price environment that does not appear likely to be as robust as it was a few years ago, requiring reductions in overall debt levels over time. We would like to further reduce, refinance, or restructure our debt if possible, and we plan to monitor the market and be opportunistic in any debt transactions based on market conditions. These potential transactions could include purchases of our subordinated debt in the open market, cash tenders for our debt, or public or privately negotiated debt exchanges, including debt for equity exchanges, or future potential debt reduction with proceeds of issuances of equity, asset sales and other cash-generating activities. Any equity that we issue could lead to dilution of our current stockholders and possible declines in our common stock price.

Senior Secured Bank Credit Facility. In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (the “Bank Credit Agreement”). In May 2017, as part of our semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $1.05 billion, with the next such redetermination scheduled for November 2017. As of June 30, 2017, we had $490.0 million of debt outstanding and $62.2 million in letters of credit on the senior secured bank credit facility, leaving us with significant liquidity. The Bank Credit Agreement contains certain restrictive covenants and financial performance covenants through the maturity of the facility. In conjunction with the May 2017 borrowing base redetermination, we amended certain terms and financial performance covenants through the remaining term of the Bank Credit Agreement in order to provide more flexibility in managing the credit extended by our lenders. The amendments to the Bank Credit Agreement included the following:

- Eliminating the consolidated total net debt to consolidated EBITDAX covenants that were scheduled to go into effect starting in 2018 through the remaining term of the facility;
- Extending the existing consolidated senior secured debt to consolidated EBITDAX covenant through the remaining term of the facility, 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;
- Extending the existing minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0 through the remaining term of the facility, as it previously would have expired after the fourth quarter of 2017; and
- Increasing the applicable margin for ABR Loans and LIBOR Loans by 50 basis points such that the margin for ABR Loans now ranges from 1.5% to 2.5% per annum and the margin for LIBOR Loans now ranges from 2.5% to 3.5% per annum.

The requirement to maintain a current ratio of 1.0 to 1.0 was not amended, and so remains in place. Also, incurrence of additional debt (separate from debt under the credit facility) in connection with various events remains subject to a Total Leverage Test unless the consolidated total net debt to EBITDAX ratio is reduced on a pro forma basis by the event. For our financial performance covenant calculations as of June 30, 2017, our ratio of consolidated senior secured debt to consolidated EBITDAX was 1.5 to 1.0 (with a maximum permitted ratio of 3.0 to 1.0), our ratio of consolidated EBITDAX to consolidated interest charges was 1.93 to 1.0 (with a required ratio of not less than 1.25 to 1.0), and our current ratio was 2.77 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 August 7, 2017, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our bank covenants during the foreseeable future.

All of the above descriptions of our Bank Credit Agreement and the amendments thereto are qualified by the express language and defined terms contained in the Bank Credit Agreement and the Fourth Amendment to the Bank Credit Agreement dated May 3, 2017, each of which are filed as exhibits to our periodic reports filed with the SEC.

Capital Spending. We currently anticipate that our full-year 2017 capital budget, excluding capitalized interest and acquisitions, will be approximately $250 million, which includes approximately $55 million in capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs. This combined 2017 capital budget amount, excluding capitalized interest and acquisitions, is comprised of the following:

- $135 million allocated for tertiary oil field expenditures;
- $50 million allocated for other areas, primarily non-tertiary oil field expenditures;

- $10 million to be spent on $CO_2$ sources and pipelines; and
- $55 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

By year-end 2017, among other projects, we are targeting completion of the development of Phase 5 at Bell Creek Field, expansion of the recycle facility at Oyster Bayou Field, and further implementation of our Hastings redevelopment project.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the six months ended June 30, 2017 and 2016:

| | Six Months Ended June 30, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Capital expenditures by project | | |
| Tertiary oil fields | $64,768 | $63,898 |
| Non-tertiary fields | 32,772 | 10,776 |
| Capitalized internal costs (1) | 26,717 | 25,787 |
| Oil and natural gas capital expenditures | 124,257 | 100,461 |
| $CO_2$ pipelines, sources and other | 528 | 152 |
| Capital expenditures, before acquisitions and capitalized interest | 124,785 | 100,613 |
| Acquisitions of oil and natural gas properties | 89,099 | 904 |
| Capital expenditures, before capitalized interest | 213,884 | 101,517 |
| Capitalized interest | 12,801 | 12,069 |
| Capital expenditures, total | $226,685 | $113,586 |

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

For the six months ended June 30, 2017, our capital expenditures and property acquisitions were funded with $77.2 million of cash flows from operations, with additional funds provided by borrowings on our Bank Credit Agreement. For the six months ended June 30, 2016, our capital expenditures and property acquisitions were funded with cash flows from operations and borrowings on our Bank Credit Agreement, with the incremental borrowings primarily being required to cover working capital outflows.

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.

The Company has a $CO_2$ offtake agreement with Mississippi Power Company ("MSPC"), providing for our purchase of $CO_2$ generated as a byproduct of the gasification portion of their Kemper County energy facility. In June 2017, MSPC announced the immediate suspension of startup and operations activities of the lignite coal gasification portion of the Kemper County energy facility, resulting in no further sale of $CO_2$ to us while operation of the lignite coal gasification portion of the facility is suspended. Given our Jackson Dome $CO_2$ reserves and the increased efficiency of our $CO_2$ usage, we do not anticipate any material impact upon our tertiary production from a lengthy or permanent absence of offtake $CO_2$ volumes from the MSPC plant.

Our commitments and obligations consist of those detailed as of December 31, 2016, in our Form 10-K under Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations.

RESULTS OF OPERATIONS

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

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

Operating Results Table

Certain of our operating results and statistics for the comparative three and six months ended June 30, 2017 and 2016 are included in the following table:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| In thousands, except per-share and unit data | 2017 | 2016 | 2017 | 2016 |
| Operating results | | | | |
| Net income (loss) [1] | $14,399 | $(380,668) | $35,929 | $(565,861) |
| Net income (loss) per common share – basic [1] | 0.04 | (1.03) | 0.09 | (1.58) |
| Net income (loss) per common share – diluted [1] | 0.04 | (1.03) | 0.09 | (1.58) |
| Net cash provided by operating activities | 52,946 | 60,915 | 77,208 | 62,944 |
| Average daily production volumes | | | | |
| Bbls/d | 57,867 | 61,952 | 58,084 | 64,045 |
| Mcf/d | 11,444 | 15,328 | 10,616 | 17,299 |
| BOE/d [2] | 59,774 | 64,506 | 59,853 | 66,929 |
| Operating revenues | | | | |
| Oil sales | $248,317 | $244,572 | $512,291 | $429,388 |
| Natural gas sales | 2,563 | 2,096 | 4,767 | 5,083 |
| Total oil and natural gas sales | $250,880 | $246,668 | $517,058 | $434,471 |
| Commodity derivative contracts [3] | | | | |
| Receipt (payment) on settlements of commodity derivatives | $(11,767) | $52,026 | $(38,707) | $124,253 |
| Noncash fair value gains (losses) on commodity derivatives [4] | 22,140 | (150,235) | 73,682 | (245,288) |
| Commodity derivatives income (expense) | $10,373 | $(98,209) | $34,975 | $(121,035) |
| Unit prices – excluding impact of derivative settlements | | | | |
| Oil price per Bbl | $47.16 | $43.38 | $48.73 | $36.84 |
| Natural gas price per Mcf | 2.46 | 1.50 | 2.48 | 1.61 |
| Unit prices – including impact of derivative settlements [3] | | | | |
| Oil price per Bbl | $44.92 | $52.61 | $45.05 | $47.50 |
| Natural gas price per Mcf | 2.46 | 1.50 | 2.48 | 1.61 |
| Oil and natural gas operating expenses | | | | |
| Lease operating expenses | $111,318 | $100,019 | $225,158 | $202,466 |
| Marketing expenses, net of third-party purchases, and plant operating expenses | 9,964 | 10,890 | 20,052 | 22,482 |
| Production and ad valorem taxes | 18,289 | 17,040 | 39,130 | 34,218 |
| Oil and natural gas operating revenues and expenses per BOE | | | | |
| Oil and natural gas revenues | $46.12 | $42.02 | $47.73 | $35.67 |
| Lease operating expenses | 20.46 | 17.04 | 20.78 | 16.62 |
| Marketing expenses, net of third-party purchases, and plant operating expenses | 1.83 | 1.85 | 1.85 | 1.84 |
| Production and ad valorem taxes | 3.36 | 2.90 | 3.61 | 2.81 |
| $CO_2$ sources – revenues and expenses | | | | |
| $CO_2$ sales and transportation fees | $6,555 | $6,622 | $11,943 | $12,894 |
| $CO_2$ discovery and operating expenses | (513) | (1,071) | (1,106) | (1,678) |
| $CO_2$ revenue and expenses, net | $6,042 | $5,551 | $10,837 | $11,216 |

(1) Includes a pre-tax full cost pool ceiling test write-down of our oil and natural gas properties of $479.4 million and $735.4 million for the three and six months ended June 30, 2016, respectively.

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

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

(4) Noncash fair value 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 $11.8 million and $38.7 million for the three and six months ended June 30, 2017, respectively, compared to receipts on settlements of $52.0 million and $124.3 million for the three and six months ended June 30, 2016, 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.

Production

Average daily production by area for each of the four quarters of 2016 and for the first and second quarters of 2017 is shown below:

| | Average Daily Production (BOE/d) | | | | | |
|---|---|---|---|---|---|---|
| Operating Area | First Quarter 2016 | Second Quarter 2016 | Third Quarter 2016 | Fourth Quarter 2016 | First Quarter 2017 | Second Quarter 2017 |
| Tertiary oil production | | | | | | |
| Gulf Coast region | | | | | | |
| Mature properties [(1)] | 9,666 | 9,415 | 8,653 | 8,440 | 8,111 | 7,737 |
| Delhi | 3,971 | 3,996 | 4,262 | 4,387 | 4,991 | 4,965 |
| Hastings | 5,068 | 4,972 | 4,729 | 4,552 | 4,288 | 4,400 |
| Heidelberg | 5,346 | 5,246 | 5,000 | 4,924 | 4,730 | 4,996 |
| Oyster Bayou | 5,494 | 5,088 | 4,767 | 4,988 | 5,075 | 5,217 |
| Tinsley | 7,899 | 7,335 | 6,756 | 6,786 | 6,666 | 6,311 |
| Total Gulf Coast region | 37,444 | 36,052 | 34,167 | 34,077 | 33,861 | 33,626 |
| Rocky Mountain region | | | | | | |
| Bell Creek | 3,020 | 3,160 | 3,032 | 3,269 | 3,209 | 3,060 |
| Salt Creek [(2)] | — | — | — | — | — | 23 |
| Total Rocky Mountain region | 3,020 | 3,160 | 3,032 | 3,269 | 3,209 | 3,083 |
| Total tertiary oil production | 40,464 | 39,212 | 37,199 | 37,346 | 37,070 | 36,709 |
| Non-tertiary oil and gas production | | | | | | |
| Gulf Coast region | | | | | | |
| Mississippi | 673 | 1,017 | 963 | 745 | 1,342 | 1,004 |
| Texas | 6,148 | 4,104 | 4,234 | 5,143 | 4,333 | 5,002 |
| Other | 549 | 456 | 538 | 569 | 495 | 460 |
| Total Gulf Coast region | 7,370 | 5,577 | 5,735 | 6,457 | 6,170 | 6,466 |
| Rocky Mountain region | | | | | | |
| Cedar Creek Anticline | 17,778 | 16,325 | 16,017 | 15,186 | 15,067 | 15,124 |
| Other | 2,070 | 1,862 | 1,763 | 1,696 | 1,626 | 1,475 |
| Total Rocky Mountain region | 19,848 | 18,187 | 17,780 | 16,882 | 16,693 | 16,599 |
| Total non-tertiary production | 27,218 | 23,764 | 23,515 | 23,339 | 22,863 | 23,065 |
| Total continuing production | 67,682 | 62,976 | 60,714 | 60,685 | 59,933 | 59,774 |
| Property sales | | | | | | |
| 2016 property divestitures [(3)] | 1,669 | 1,530 | 819 | — | — | — |
| Total production | 69,351 | 64,506 | 61,533 | 60,685 | 59,933 | 59,774 |

(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.

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

Total Production

Total continuing production during the second quarter of 2017 averaged 59,774 BOE/d, including 36,709 Bbls/d from tertiary properties and 23,065 BOE/d from non-tertiary properties. Total continuing production during 2016 excludes production from the Williston Assets that were sold during the third quarter of 2016 and other minor property divestitures, which production totaled 1,530 BOE/d during the second quarter of 2016. This total continuing production level was relatively flat compared to first quarter of 2017 production levels of 59,933 BOE/d and represents a decrease of 3,202 BOE/d (5%) compared to second quarter of 2016 production levels.

Our production during the three and six months ended June 30, 2017 was 97% oil, slightly higher than our 96% oil production during the three and six months ended June 30, 2016.

Tertiary Production

Oil production from our tertiary operations during the second quarter of 2017 decreased 361 Bbls/d (1%) when comparing the first and second quarters of 2017 and decreased 2,503 Bbls/d (6%) compared to the same period in 2016. The year-over-year second quarter decline in production includes expected natural production declines at our mature fields and Tinsley Field in the Gulf Coast region due to our lower capital expenditure level throughout 2016, further impacted by planned downtime at Hastings Field as we expanded our tertiary development and performed conformance work. This decline was partially offset by both increased production due to continued $CO_2$ enhanced oil recovery response and natural gas liquids volumes from the plant at Delhi Field, which began operation in late 2016.

Non-Tertiary Production

Continuing production from our non-tertiary operations averaged 23,065 BOE/d during the second quarter of 2017, an increase of 202 BOE/d (1%) compared to the first quarter of 2017 and a decrease of 699 BOE/d (3%) compared to the second quarter of 2016 levels. The year-over-year decrease was primarily due to natural production declines at Cedar Creek Anticline, partially offset by increased production at Thompson Field as the production in the prior-year period was impacted by weather-related downtime.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and six months ended June 30, 2017 increased 2% and 19%, respectively, compared to these revenues for the same periods in 2016. The changes in our oil and natural gas revenues are due to changes in production quantities and commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

| | Three Months Ended June 30, 2017 vs. 2016 | | Six Months Ended June 30, 2017 vs. 2016 | |
|---|---|---|---|---|
| In thousands | Increase (Decrease) in Revenues | Percentage Increase (Decrease) in Revenues | Increase (Decrease) in Revenues | Percentage Increase (Decrease) in Revenues |
| Change in oil and natural gas revenues due to: | | | | |
| Decrease in production | $(18,094) | (7)% | $(48,066) | (11)% |

| | | | | | |
|---|---|---|---|---|---|
| Increase in commodity prices | 22,306 | 9 % | 130,653 | 30 % |
| Total increase in oil and natural gas revenues | $4,212 | 2 % | $82,587 | 19 % |

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first quarters, second quarters, and six months ended June 30, 2017 and 2016:

| | Three Months Ended March 31, | | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| Average net realized prices: | | | | | | |
| Oil price per Bbl | $50.31 | $30.71 | $47.16 | $43.38 | $48.73 | $36.84 |
| Natural gas price per Mcf | 2.50 | 1.70 | 2.46 | 1.50 | 2.48 | 1.61 |
| Price per BOE | 49.35 | 29.76 | 46.12 | 42.02 | 47.73 | 35.67 |
| Average NYMEX differentials: | | | | | | |
| Oil per Bbl | $(1.64) | $(3.02) | $(1.16) | $(2.18) | $(1.39) | $(2.81) |
| Natural gas per Mcf | (0.57) | (0.29) | (0.69) | (0.73) | (0.63) | (0.50) |

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. 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 negative $0.78 per Bbl and a negative $1.22 per Bbl during the second quarters of 2017 and 2016, respectively, and a negative $1.42 per Bbl during the first 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 quarterly average LLS-to-NYMEX differential (on a trade-month basis) was a positive $1.95 per Bbl in the second quarter of 2017, a slight decrease from the positive $2.04 per Bbl in the second quarter of 2016 and an increase from the positive $1.58 per Bbl in the first quarter of 2017. During the second quarter of 2017, 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 $1.96 per Bbl and $3.98 per Bbl below NYMEX during the second quarter of 2017 and 2016, respectively, and $2.09 per Bbl below NYMEX during the first 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 and six months ended June 30, 2017 and 2016:

| | Three Months Ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| In thousands | 2017 | 2016 | 2017 | 2016 |
| Receipt (payment) on settlements of commodity derivatives | $(11,767) | $52,026 | $(38,707) | $124,253 |
| Noncash fair value gains (losses) on commodity derivatives [1] | 22,140 | (150,235) | 73,682 | (245,288) |
| Total income (expense) | $10,373 | $(98,209) | $34,975 | $(121,035) |

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

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

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In order to provide a level of price protection to a portion of our oil production, we have entered into a combination of oil swaps, collars, and three-way collars for the second half of 2017 and throughout 2018. The following table summarizes our commodity derivative contracts as of August 7, 2017:

| | | Jul-17 | Aug-17 | Sept-17 | 4Q17 | 2018 |
|---|---|---|---|---|---|---|
| WTI NYMEX | Volumes Hedged (Bbls/d) | — | 3,750 | 7,000 | 9,000 | 9,000 |
| Fixed-Price Swaps | Swap Price (1) | — | $49.20 | $49.60 | $49.67 | $50.08 |
| WTI NYMEX | Volumes Hedged (Bbls/d) | — | — | — | 1,000 | — |
| Collars | Ceiling Price / Floor (1) | — | — | — | $70 / $40 | — |
| WTI NYMEX | Volumes Hedged (Bbls/d) | 14,500 | 14,500 | 14,500 | 14,000 | 15,000 |
| 3-Way Collars | Ceiling Price / Floor / Sold Put Price (1)(2) | $69.09 / $40 / $30 | $69.09 / $40 / $30 | $69.09 / $40 / $30 | $65.79 / $41.07 / $31.07 | $53.88 / $46.50 / $36.50 |
| Argus LLS | Volumes Hedged (Bbls/d) | 2,000 | 2,000 | 2,000 | 1,000 | — |
| 3-Way Collars | Ceiling Price / Floor / Sold Put Price (1)(2) | $69.25 / $41 / $31 | $69.25 / $41 / $31 | $69.25 / $41 / $31 | $70.25 / $41 / $31 | — |
| | Total Volumes Hedged (Bbls/d) | 16,500 | 20,250 | 23,500 | 25,000 | 24,000 |

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

Commodity derivative contracts in place for the second half of 2017 solely include collars and three-way collars. Based on current contracts in place and NYMEX oil futures prices as of August 7, 2017, which average approximately $50 per Bbl for the remainder of 2017, minimal or no settlements are currently expected during the second half of 2017. The details of our outstanding commodity derivative contracts at June 30, 2017, are included in Note 5, Commodity Derivative Contracts, to the Unaudited Condensed Consolidated Financial Statements. Also, see Item 3, Quantitative and Qualitative Disclosures about Market Risk below for additional discussion on our commodity derivative contracts.

Production Expenses

Lease Operating Expenses

| | Three Months Ended | | Six Months Ended | |
|---|---|---|---|---|
| | June 30, | | June 30, | |
| In thousands, except per-BOE data | 2017 | 2016 | 2017 | 2016 |
| Total lease operating expenses | $111,318 | $100,019 | $225,158 | $202,466 |
| Total lease operating expenses per BOE | $20.46 | $17.04 | $20.78 | $16.62 |

Total lease operating expenses increased $11.3 million (11%) and $22.7 million (11%) on an absolute-dollar basis, or $3.42 (20%) and $4.16 (25%) on a per-BOE basis during the three and six months ended June 30, 2017, respectively, compared to levels in the same periods in 2016. Our lease operating expenses during the current-year periods were impacted by increased workover and other repair activity at certain fields, as workover activity was significantly curtailed during 2016 due to the lower oil price environment, as well as higher power and fuel costs. Lease operating expenses were impacted to a smaller degree by incremental operating costs, including contract labor and fuel costs, related to the newly operating Delhi NGL plant. The six-month period was further impacted by higher $CO_2$ expense during the period as a result of higher volumes and an increase in the cost of $CO_2$ during the comparative first quarters.

Currently, our $CO_2$ expense comprises approximately 20% of our typical tertiary lease operating expenses, and for the $CO_2$ reserves we already own, consists of $CO_2$ production expenses, and for the $CO_2$ reserves we do not own, consists of our purchase of $CO_2$ from royalty and working interest owners and industrial sources. During the second quarters of 2017 and 2016, approximately 58% and 55%, respectively, of the $CO_2$ utilized in our $CO_2$ floods consisted of $CO_2$ owned and produced by us (our net revenue interest). The price we pay others for $CO_2$ varies by source and is generally indexed to oil prices. When combining the production cost of the $CO_2$ we own with what we pay third parties for $CO_2$, including taxes paid on $CO_2$ production but excluding depletion, depreciation and amortization of capital expended at our $CO_2$ source fields and industrial sources, our average cost of $CO_2$ was approximately $0.38 per Mcf during the second quarter of 2017, compared to $0.41 per Mcf during the second quarter of 2016 and first quarter of 2017. These decreases were partially attributable to lower utilization of industrial-sourced $CO_2$, which has a higher average cost than our naturally-occurring $CO_2$ sources, and higher $CO_2$ injection volumes.

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, and to a lesser extent expenses related to our Riley Ridge gas processing facility. Marketing and plant operating expenses were $13.9 million and $13.0 million for the three months ended June 30, 2017 and 2016, respectively, and $27.9 million and $26.2 million for the six months ended June 30, 2017 and 2016, respectively.

Taxes Other Than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income was relatively unchanged during the three months ended June 30, 2017 compared to the same prior-year period and increased $3.0 million (8%) during the six months ended June 30, 2017 compared to the same period in 2016, 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 | | Six Months Ended | |
|---|---|---|---|---|
| | June 30, | | June 30, | |
| In thousands, except per-BOE data and employees | 2017 | 2016 | 2017 | 2016 |
| Gross cash compensation and administrative costs | $63,302 | $61,742 | $129,749 | $141,480 |
| Gross stock-based compensation | 6,044 | 4,241 | 11,432 | 7,125 |
| Operator labor and overhead recovery charges | (32,577 ) | (32,865 ) | (64,108 ) | (67,998 ) |
| Capitalized exploration and development costs | (10,980 ) | (10,573 ) | (23,043 ) | (24,161 ) |
| Net G&A expense | $25,789 | $22,545 | $54,030 | $56,446 |
| | | | | |
| G&A per BOE: | | | | |
| Net administrative costs | $3.85 | $3.33 | $4.16 | $4.35 |
| Net stock-based compensation | 0.89 | 0.51 | 0.83 | 0.28 |
| Net G&A expenses | $4.74 | $3.84 | $4.99 | $4.63 |
| | | | | |
| Employees as of June 30 | 1,073 | 1,084 | | |

Our gross G&A expenses increased $3.4 million (5%) on an absolute-dollar basis during the three months ended June 30, 2017 compared to that in the same prior-year period, primarily due to compensation associated with the retirement of our long-time chief executive officer. Gross G&A expenses decreased $7.4 million (5%) during the six months ended June 30, 2017 compared to the same period in 2016, primarily due to the inclusion of severance-related expenses of approximately $9.3 million in the prior-year period associated with the 2016 involuntary workforce reduction, partially offset by the CEO retirement compensation noted above.

Net G&A expense on a per-BOE basis increased 23% and 8% during the three and six months ended June 30, 2017, respectively, compared to levels in the same periods in 2016 due to lower production volumes during the 2017 periods and the items previously mentioned impacting gross G&A.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well.  In addition, salaries associated with field personnel are initially recorded as gross cash compensation and administrative costs and subsequently reclassified to lease operating expenses or capitalized to field development costs to the extent those individuals are dedicated to oil and gas production, exploration, and development activities.

Interest and Financing Expenses

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| In thousands, except per-BOE data and interest rates | 2017 | 2016 | 2017 | 2016 |
| Cash interest (1) | $43,352 | $43,148 | $85,852 | $87,793 |
| Less: interest on 2021 Senior Secured Notes not reflected as interest for financial reporting purposes (1) | (12,588) | (7,036) | (25,157) | (7,036) |
| Noncash interest expense | 1,444 | 6,235 | 3,345 | 9,541 |
| Less: capitalized interest | (8,147) | (6,289) | (12,801) | (12,069) |
| Interest expense, net | $24,061 | $36,058 | $51,239 | $78,229 |
| Interest expense, net per BOE | $4.42 | $6.14 | $4.73 | $6.42 |
| Average debt principal outstanding | $2,869,319 | $3,006,304 | $2,844,215 | $3,166,222 |
| Average interest rate (2) | 6.0% | 5.7% | 6.0% | 5.5% |

(1) Cash interest is presented on an accrual basis, and includes the portion of interest on our 2021 Senior Secured Notes (interest on which is to be paid semiannually May 15 and November 15 of each year) 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.

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

As reflected in the table above, cash interest during the three months ended June 30, 2017 was relatively unchanged from that in the prior-year period and decreased $1.9 million (2%) during the six months ended June 30, 2017 when compared to the same period in 2016 due primarily to repurchasing a total of $181.9 million principal amount of our existing senior subordinated notes at a discount to par value in open-market transactions during the first nine months of 2016. Noncash interest expense during the three and six months ended June 30, 2017 decreased when compared to the same prior-year periods primarily due to the 2016 period including a $4.5 million write-off of debt issuance costs associated with our senior secured bank credit facility following the May 2016 redetermination which reduced our borrowing base. Capitalized interest during the three months ended June 30, 2017 increased $1.9 million (30%) compared to the same period in 2016, primarily due to an increase in the number of projects that qualify for interest capitalization.

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

| | Three Months Ended | | Six Months Ended | |
|---|---|---|---|---|
| | June 30, | | June 30, | |
| In thousands, except per-BOE data | 2017 | 2016 | 2017 | 2016 |
| Oil and natural gas properties | $29,165 | $40,805 | $56,983 | $90,821 |
| $CO_2$ properties, pipelines, plants and other property and equipment | 21,987 | 25,736 | 45,364 | 53,086 |
| Total DD&A | $51,152 | $66,541 | $102,347 | $143,907 |
| | | | | |
| DD&A per BOE: | | | | |
| Oil and natural gas properties | $5.36 | $7.01 | $5.26 | $7.50 |
| $CO_2$ properties, pipelines, plants and other property and equipment | 4.04 | 4.33 | 4.19 | 4.31 |
| Total DD&A cost per BOE | $9.40 | $11.34 | $9.45 | $11.81 |
| | | | | |
| Write-down of oil and natural gas properties | $— | $479,400 | $— | $735,400 |

The decrease in our oil and natural gas properties depletion was primarily due to a reduction in depletable costs associated with our reserves base resulting from the full cost pool ceiling test write-downs recognized during 2016 and an overall reduction in future development costs, partially offset by reductions in proved oil and natural gas reserve quantities. The per-BOE decrease was also partially offset by a decrease in production volumes during the second quarter of 2017 when compared to production in the 2016 period.

The decrease in depletion and depreciation of our $CO_2$ properties, pipelines, plants and other property and equipment was primarily due to a decrease in plant depreciation due to the accelerated depreciation charge at the Riley Ridge gas processing facility during the fourth quarter of 2016.

2016 Write-Down of Oil and Natural Gas Properties

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. The falling prices in 2016, relative to 2015 prices, led to our recognizing full cost pool ceiling test write-downs of $479.4 million and $256.0 million during the three months ended June 30, 2016 and March 31, 2016, respectively. We did not record a full cost pool ceiling test write-down in the first or second quarters of 2017.

Income Taxes

| | Three Months Ended | | Six Months Ended | |
|---|---|---|---|---|
| | June 30, | | June 30, | |
| In thousands, except per-BOE amounts and tax rates | 2017 | 2016 | 2017 | 2016 |
| Current income tax benefit | $(5,965) | $— | $(19,900) | $(5) |
| Deferred income tax expense (benefit) | 16,238 | (222,940) | 51,147 | (318,055) |
| Total income tax expense (benefit) | $10,273 | $(222,940) | $31,247 | $(318,060) |
| Average income tax expense (benefit) per BOE | $1.89 | $(37.98) | $2.88 | $(26.11) |
| Effective tax rate | 41.6% | 36.9% | 46.5% | 36.0% |
| Total net deferred tax liability | $345,025 | $519,207 | | |

Our income taxes are based on an estimated statutory rate of approximately 38% in 2017 and 2016. Effective January 1, 2016, we adopted Accounting Standards Update 2016-09 (“ASU 2016-09”), Improvements to Employee Share-Based Payment

Accounting, which impacted the timing of when excess tax benefits or tax shortfalls are recognized. Our effective tax rate for the three months ended June 30, 2017, was higher than our estimated statutory rate, primarily due to the impact of alternative minimum tax credit usage during the quarter. Our effective tax rate for the three months ended June 30, 2016 was lower than our estimated statutory rate, primarily due to the full cost pool ceiling test write-down recorded during the quarter. Our effective tax rates for the six months ended June 30, 2017 and 2016 were impacted by a tax shortfall on the stock-based compensation deduction (e.g., the compensation expense recognized in the financial statements was greater than the actual compensation realized resulting in a shortfall in the income tax deduction for stock awards that vested during the second quarter) which, prior to the adoption of ASU 2016-09, was recorded as an adjustment to equity. The current income tax benefits during the three and six months ended June 30, 2017, represent the estimated receivable resulting from alternative minimum tax credits. The deferred income tax benefits during the three and six months ended June 30, 2016, were primarily due to the impact of the write-down of our oil and natural gas properties during the periods.

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. As of June 30, 2017, we had $36.5 million of deferred tax assets associated with State of Louisiana net operating losses. As the result of falling commodity prices, combined with a new tax law enacted in the State of Louisiana effective June 30, 2015, which limits a company's utilization of certain deductions, including our net operating loss carryforwards, we recognized tax valuation allowances totaling $36.5 million during 2015 and 2016, which reduced the carrying value of these deferred tax assets to zero as of December 31, 2016. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

As of June 30, 2017, we had an unrecognized tax benefit of $5.4 million related to an uncertain tax position. The unrecognized tax benefit was recorded during 2015 as a direct reduction of the associated deferred tax asset and, if recognized, would not materially affect our annual effective tax rate. The tax benefit from an uncertain tax position will only be recognized if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. We currently do not expect a material change to the uncertain tax position within the next 12 months. Our policy is to recognize penalties and interest related to uncertain tax positions in income tax expense; however, no such amounts were accrued related to the uncertain tax position as of June 30, 2017.

As of June 30, 2017, we had an estimated $51.1 million of enhanced oil recovery credits to carry forward related to our tertiary operations, $21.6 million of research and development credits, and $23.9 million of alternative minimum tax credits (net of $17.3 million related to the estimated credits to be applied to our 2016 and 2017 tax return) that can be utilized to reduce our current income taxes during 2017 or future years.  The enhanced oil recovery credits and research and development credits do not begin to expire until 2023 and 2031, respectively.

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Per-BOE Data

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| Per-BOE data | 2017 | 2016 | 2017 | 2016 |
| Oil and natural gas revenues | $46.12 | $42.02 | $47.73 | $35.67 |
| Receipt (payment) on settlements of commodity derivatives | (2.16) | 8.86 | (3.57) | 10.20 |
| Lease operating expenses | (20.46) | (17.04) | (20.78) | (16.62) |
| Production and ad valorem taxes | (3.36) | (2.90) | (3.61) | (2.81) |
| Marketing expenses, net of third-party purchases, and plant operating expenses | (1.83) | (1.85) | (1.85) | (1.84) |
| Production netback | 18.31 | 29.09 | 17.92 | 24.60 |
| $CO_2$ sales, net of operating and exploration expenses | 1.12 | 0.95 | 1.00 | 0.92 |
| General and administrative expenses | (4.74) | (3.84) | (4.99) | (4.63) |
| Interest expense, net | (4.42) | (6.14) | (4.73) | (6.42) |
| Other | 1.72 | (4.22) | 2.53 | (2.16) |
| Changes in assets and liabilities relating to operations | (2.26) | (5.46) | (4.60) | (7.14) |
| Cash flows from operations | 9.73 | 10.38 | 7.13 | 5.17 |
| DD&A | (9.40) | (11.34) | (9.45) | (11.81) |
| Write-down of oil and natural gas properties | — | (81.67) | — | (60.37) |
| Deferred income taxes | (2.99) | 37.98 | (4.72) | 26.11 |
| Gain on debt extinguishment | — | 2.09 | — | 8.81 |
| Noncash fair value gains (losses) on commodity derivatives (1) | 4.07 | (25.59) | 6.80 | (20.14) |
| Other noncash items | 1.24 | 3.30 | 3.56 | 5.78 |
| Net income (loss) | $2.65 | $(64.85) | $3.32 | $(46.45) |

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

## CRITICAL ACCOUNTING POLICIES

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

## FORWARD-LOOKING INFORMATION

The data and/or statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, financial forecasts, future hydrocarbon prices and timing and degree of any price recovery versus the length or severity of the current commodity price downturn, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to 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, availability of capital, borrowing capacity, future interest rates, availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, closing of proposed asset sales or the timing or proceeds thereof, estimated timing of commencement of $CO_2$ flooding of particular fields or areas, likelihood of completion of to-be-constructed industrial plants and the initial date of capture of $CO_2$ from such plants, timing of $CO_2$ injections and initial production responses in tertiary flooding projects, acquisition plans and proposals and dispositions, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, $CO_2$ reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, potential increases in regional or 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,” “anticipat “projected,” “preliminary,” “should,” “assume,” “believe,” “may” or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management’s current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC in future periods; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of credit in the commercial banking market, fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, or forest fires; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, 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.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable rate debt.  These debt agreements expose us to market risk related to changes in interest rates. As of June 30, 2017, we had $490.0 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 Denbury Onshore or Denbury fail to make a payment due under the pipeline financing lease agreement or upon other specified defaults set out in the pipeline financing lease agreement (filed as Exhibit 99.1 to the Form 8-K filed with the SEC on June 5, 2008). The fair values of our 2021 Senior Secured 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 June 30, 2017:

| In thousands | 2017 | 2019 | 2021 | 2022 | 2023 | Total | Fair Value |
|---|---|---|---|---|---|---|---|
| Variable rate debt: | | | | | | | |
| Senior Secured Bank Credit Facility (weighted average interest rate of 4.2% at June 30, 2017) | $ — | $490,000 | $ — | $ — | $ — | $490,000 | $490,000 |
| Fixed rate debt: | | | | | | | |
| 9% Senior Secured Second Lien Notes due 2021 | — | — | 614,919 | — | — | 614,919 | 585,710 |
| 6 % Senior Subordinated Notes due 2021 | — | — | 215,144 | — | — | 215,144 | 125,859 |
| 5½% Senior Subordinated Notes due 2022 | — | — | — | 772,912 | — | 772,912 | 438,628 |
| 4 % Senior Subordinated Notes due 2023 | — | — | — | — | 622,297 | 622,297 | 331,373 |
| Other Subordinated Notes | 2,250 | — | — | — | — | 2,250 | 2,250 |

See Note 3, Long-Term Debt, to the Unaudited Condensed Consolidated Financial Statements for details regarding our long-term debt.

Oil and Natural Gas Derivative Contracts

Historically, we have entered into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production and to provide more certainty to our future cash flows.  We do not hold or issue derivative financial instruments for trading purposes.  Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, and fixed-price swaps enhanced with a sold put.  The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices.  In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2018 using both NYMEX and LLS fixed-price swaps, collars and three-way collars. Due to the volatility experienced and the previous downward trend in oil prices over the past two years, we have reduced our hedged level and duration of new derivative contracts; thus, the percentage of our forecasted production we have hedged and the duration of our hedges are less than what we have had in the recent past. However, we will continue to evaluate the production we hedge in light of our levels of debt, financial strength and expectation of future commodity prices. See also Note 5, Commodity Derivative Contracts, and Note 6, Fair Value Measurements, to the Unaudited

Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our commodity derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our commodity derivative contracts are with parties that are lenders under our senior secured bank credit facility (or affiliates of such lenders). We have included an estimate of nonperformance risk in the fair value measurement of our commodity derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

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

At June 30, 2017, our commodity derivative contracts were recorded at their fair value, which was a net asset of $4.4 million, a $22.1 million increase from the $17.7 million net liability recorded at March 31, 2017, and a $73.7 million increase from the $69.3 million net liability recorded at December 31, 2016. Changes in this value are comprised of the expiration of commodity derivative contracts during the three and six months ended June 30, 2017, new commodity derivative contracts entered into during 2017 for future periods, and to the changes in oil futures prices between December 31, 2016 and June 30, 2017.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of June 30, 2017, and assuming both a 10% increase and decrease thereon, we would expect to make payments on our crude oil derivative contracts as shown in the following table:

| In thousands | Receipt / (Payment) Crude Oil Derivative Contracts |
|---|---|
| Based on: | |
| Futures prices as of June 30, 2017 | $ 2,123 |
| 10% increase in prices | (3,170 ) |
| 10% decrease in prices | 13,572 |

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2017, 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 second quarter of fiscal 2017, 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.

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## 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.

#### Settlement of Mississippi Environmental Matter

For the past two years, the Company has been in negotiations with the Mississippi Department of Environmental Quality ("MDEQ") regarding a February 2015 notice from the MDEQ related to a discharge of materials at the West Heidelberg Field in Jasper County, Mississippi in the third quarter of 2013. In late April 2017, we entered into an Agreed Order with the MDEQ settling the claims covered by the notice, which Agreed Order provides for the Company's payment of a civil penalty of $195,000 and for it to maintain certain future well monitoring.

#### 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, we assumed a 20-year helium supply contract under which we agreed to supply to a third-party purchaser the helium separated from the full well stream by operation of the gas processing facility. 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 capped at $8.0 million per contract year and are capped at an aggregate of $46.0 million over the remaining term of the contract. As the gas processing facility has been shut-in since mid-2014, we have not been able to supply helium to the third-party purchaser under the helium supply contract. In a case originally filed in November 2014 by APMTG Helium, LLC, the third-party helium purchaser, in the Ninth Judicial District Court of Sublette County, Wyoming, after a week of trial during February 2017 on the third-party purchaser's claim for multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract, and on our claim that the contractual obligation is excused by virtue of events that fall within the force majeure provisions in the helium supply contract, the trial was stayed until November 2017. The Company plans to continue to vigorously defend its position and pursue its claim, 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.

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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 second quarter of 2017:

| Month | Total Number of Shares Purchased (1) | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions) (2) |
|---|---|---|---|---|
| April 2017 | — | $ — | — | $ 210.1 |
| May 2017 | — | — | — | 210.1 |
| June 2017 | 2,403 | 1.51 | — | 210.1 |
| Total | 2,403 | | — | |

(1) Stock repurchases during the second quarter of 2017 were made in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted and performance shares.

(2) In October 2011, we commenced a common share repurchase program, which has been approved for up to an aggregate of $1.162 billion of Denbury common shares by the Company's Board of Directors. This program has effectively been suspended and we do not anticipate repurchasing shares of our common stock as long as industry commodity pricing and general economic conditions persist. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

Between early October 2011, when we announced commencement of a common share repurchase program, and October 2015, we repurchased 64.4 million shares of Denbury common stock (approximately 16.0% of our outstanding shares of common stock at September 30, 2011) for $951.8 million, with no repurchases made since October 2015.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

| Exhibit No. | Exhibit |
|---|---|
| 10(a) | Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of May 24, 2017 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 26, 2017, File No. 001-12935). |
| 10(b)* | Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. |
| 10(c)* | Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. |
| 31(a)* | Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31(b)* | Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32* | Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 101* | Interactive Data Files. |

* Included herewith.

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SIGNATURES

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

| | |
|---|---|
| | DENBURY RESOURCES INC. |
| August 8, 2017 | /s/ Mark C. Allen<br>Mark C. Allen<br>Sr. Vice President and Chief Financial Officer |
| August 8, 2017 | /s/ Alan Rhoades<br>Alan Rhoades<br>Vice President and Chief Accounting Officer |

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INDEX TO EXHIBITS

| Exhibit No. | Exhibit |
|---|---|
| 10(b) | Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. |
| 10(c) | Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. |
| 31(a) | Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31(b) | Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32 | Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 101 | Interactive Data Files. |