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

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

For the quarterly period ended June 30, 2019
OR

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

For the transition period from _____ to _____

Commission file number: **001-12935**

DENBURY RESOURCES INC.
(Exact name of registrant as specified in its charter)

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class:	Trading Symbol:	Name of Each Exchange on Which Registered:
Common Stock $.001 Par Value	DNR	New York Stock Exchange

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

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

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

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

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

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

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

The number of shares outstanding of the registrant's Common Stock, $.001 par value, as of July 31, 2019, was 469,661,433.

Denbury Resources Inc.

Table of Contents

		Page
	PART I. FINANCIAL INFORMATION	
Item 1.	Financial Statements	
	Unaudited Condensed Consolidated Balance Sheets as of June 30, 2019 and December 31, 2018	3
	Unaudited Condensed Consolidated Statements of Operations for the Three and Six Months Ended June 30, 2019 and 2018	4
	Unaudited Condensed Consolidated Statements of Cash Flows for the Six Months Ended June 30, 2019 and 2018	5
	Unaudited Condensed Consolidated Statement of Changes in Stockholders' Equity for the Three and Six Months Ended June 30, 2019 and 2018	6
	Notes to Unaudited Condensed Consolidated Financial Statements	7
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	20
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	37
Item 4.	Controls and Procedures	39
	PART II. OTHER INFORMATION	
Item 1.	Legal Proceedings	40
Item 1A.	Risk Factors	41
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	42
Item 3.	Defaults Upon Senior Securities	42
Item 4.	Mine Safety Disclosures	42
Item 5.	Other Information	42
Item 6.	Exhibits	43
	Signatures	44

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, 2019	December 31, 2018
Assets		
Current assets		
Cash and cash equivalents	$ 341	$ 38,560
Accrued production receivable	135,697	125,788
Trade and other receivables, net	28,469	26,970
Derivative assets	24,447	93,080
Other current assets	14,989	11,896
Total current assets	203,943	296,294
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	11,275,255	11,072,209
Unevaluated properties	941,336	996,700
CO_2 properties	1,198,657	1,196,795
Pipelines and plants	2,324,265	2,302,817
Other property and equipment	223,666	250,279
Less accumulated depletion, depreciation, amortization and impairment	(11,583,497)	(11,500,190)
Net property and equipment	4,379,682	4,318,610
Operating lease right-of-use assets	36,421	—
Derivative assets	9,488	4,195
Other assets	102,500	104,123
Total assets	$ 4,732,034	$ 4,723,222
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 180,283	$ 198,380
Oil and gas production payable	63,034	61,288
Derivative liabilities	1,912	—
Current maturities of long-term debt (including future interest payable of $85,677 and $85,303, respectively – see Note 4)	101,829	105,125
Operating lease liabilities	6,739	—
Total current liabilities	353,797	364,793
Long-term liabilities		
Long-term debt, net of current portion (including future interest payable of $121,982 and $164,914, respectively – see Note 4)	2,466,127	2,664,211
Asset retirement obligations	181,491	174,470
Derivative liabilities	22	—
Deferred tax liabilities, net	362,303	309,758
Operating lease liabilities	45,391	—
Other liabilities	52,227	68,213
Total long-term liabilities	3,107,561	3,216,652
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, 750,000,000 shares authorized; 464,166,479 and 462,355,725 shares issued, respectively	464	462
Paid-in capital in excess of par	2,694,184	2,685,211
Accumulated deficit	(1,412,094)	(1,533,112)
Treasury stock, at cost, 2,474,904 and 1,941,749 shares, respectively	(11,878)	(10,784)
Total stockholders' equity	1,270,676	1,141,777
Total liabilities and stockholders' equity	$ 4,732,034	$ 4,723,222

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Revenues and other income				
Oil, natural gas, and related product sales	$ 330,421	$ 375,565	$ 624,998	$ 715,586
CO_2 sales and transportation fees	7,986	6,715	16,556	14,267
Purchased oil sales	2,591	346	2,806	1,403
Other income	2,367	4,437	4,457	9,041
Total revenues and other income	343,365	387,063	648,817	740,297
Expenses				
Lease operating expenses	117,932	120,384	243,355	238,740
Transportation and marketing expenses	11,236	10,062	22,009	20,555
CO_2 discovery and operating expenses	581	500	1,137	962
Taxes other than income	25,517	27,234	49,302	54,553
Purchased oil expenses	2,564	289	2,777	1,162
General and administrative expenses	17,506	19,412	36,431	39,644
Interest, net of amounts capitalized of $8,238, $8,851, $18,772 and $17,303, respectively	20,416	16,208	37,814	33,447
Depletion, depreciation, and amortization	58,264	52,944	115,561	105,395
Commodity derivatives expense (income)	(24,760)	96,199	58,617	145,024
Gain on debt extinguishment	(100,346)	—	(100,346)	—
Other expenses	2,386	4,178	6,524	7,564
Total expenses	131,296	347,410	473,181	647,046
Income before income taxes	212,069	39,653	175,636	93,251
Income tax provision	65,377	9,431	54,618	23,451
Net income	$ 146,692	$ 30,222	$ 121,018	$ 69,800
Net income per common share				
Basic	$ 0.32	$ 0.07	$ 0.27	$ 0.17
Diluted	$ 0.32	$ 0.07	$ 0.26	$ 0.15
Weighted average common shares outstanding				
Basic	452,612	433,467	452,169	413,217
Diluted	467,427	457,165	461,460	454,466

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30,	
	2019	**2018**
Cash flows from operating activities		
Net income	$ 121,018	$ 69,800
Adjustments to reconcile net income to cash flows from operating activities		
Depletion, depreciation, and amortization	115,561	105,395
Deferred income taxes	52,545	25,237
Stock-based compensation	6,865	5,152
Commodity derivatives expense (income)	58,617	145,024
Receipt (payment) on settlements of commodity derivatives	6,657	(88,127)
Gain on debt extinguishment	(100,346)	—
Debt issuance costs and discounts	2,901	2,268
Other, net	(57)	(5,107)
Changes in assets and liabilities, net of effects from acquisitions		
Accrued production receivable	(9,909)	(17,385)
Trade and other receivables	(271)	(320)
Other current and long-term assets	(3,389)	(5,627)
Accounts payable and accrued liabilities	(33,320)	14,999
Oil and natural gas production payable	1,746	(4,501)
Other liabilities	(5,618)	(1,182)
Net cash provided by operating activities	213,000	245,626
Cash flows from investing activities		
Oil and natural gas capital expenditures	(148,254)	(134,458)
Pipelines and plants capital expenditures	(10,591)	(7,882)
Net proceeds from sales of oil and natural gas properties and equipment	431	2,077
Other	(725)	5,365
Net cash used in investing activities	(159,139)	(134,898)
Cash flows from financing activities		
Bank repayments	(281,000)	(1,153,653)
Bank borrowings	361,000	1,093,653
Interest payments treated as a reduction of debt	(42,558)	(37,233)
Cash paid in conjunction with debt exchange	(120,007)	—
Costs of debt financing	(9,332)	—
Pipeline financing and capital lease debt repayments	(7,273)	(12,625)
Other	12,899	(628)
Net cash used in financing activities	(86,271)	(110,486)
Net increase (decrease) in cash, cash equivalents, and restricted cash	(32,410)	242
Cash, cash equivalents, and restricted cash at beginning of period	54,949	15,992
Cash, cash equivalents, and restricted cash at end of period	$ 22,539	$ 16,234

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		
	Shares	Amount			Shares	Amount	Total Equity
Balance – December 31, 2018	462,355,725	$ 462	$ 2,685,211	$ (1,533,112)	1,941,749	$ (10,784)	$ 1,141,777
Issued or purchased pursuant to stock compensation plans	1,331,050	2	—	—	—	—	2
Issued pursuant to directors' compensation plan	41,487	—	—	—	—	—	—
Stock-based compensation	—	—	4,306	—	—	—	4,306
Tax withholding – stock compensation	—	—	—	—	531,494	(1,091)	(1,091)
Net loss	—	—	—	(25,674)	—	—	(25,674)
Balance – March 31, 2019	463,728,262	464	2,689,517	(1,558,786)	2,473,243	(11,875)	1,119,320
Issued or purchased pursuant to stock compensation plans	400,850	—	—	—	—	—	—
Issued pursuant to directors' compensation plan	37,367	—	—	—	—	—	—
Stock-based compensation	—	—	4,667	—	—	—	4,667
Tax withholding – stock compensation	—	—	—	—	1,661	(3)	(3)
Net income	—	—	—	146,692	—	—	146,692
Balance – June 30, 2019	464,166,479	$ 464	$ 2,694,184	$ (1,412,094)	2,474,904	$ (11,878)	$ 1,270,676

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		
	Shares	Amount			Shares	Amount	Total Equity
Balance – December 31, 2017	402,549,346	$ 403	$ 2,507,828	$ (1,855,810)	457,041	$ (4,256)	$ 648,165
Issued or purchased pursuant to stock compensation plans	378,595	—	—	—	—	—	—
Stock-based compensation	—	—	3,303	—	—	—	3,303
Tax withholding – stock compensation	—	—	—	—	330,826	(828)	(828)
Net income	—	—	—	39,578	—	—	39,578
Balance – March 31, 2018	402,927,941	403	2,511,131	(1,816,232)	787,867	(5,084)	690,218
Issued or purchased pursuant to stock compensation plans	36,437	—	—	—	—	—	—
Issued pursuant to notes conversion	55,249,999	55	161,995	—	—	—	162,050
Stock-based compensation	—	—	3,226	—	—	—	3,226
Tax withholding – stock compensation	—	—	—	—	18,451	(71)	(71)
Net income	—	—	—	30,222	—	—	30,222
Balance – June 30, 2018	458,214,377	$ 458	$ 2,676,352	$ (1,786,010)	806,318	$ (5,155)	$ 885,645

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

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

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2018 (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, 2019, our consolidated results of operations for the three and six months ended June 30, 2019 and 2018, our consolidated cash flows for the six months ended June 30, 2019 and 2018, and our consolidated statements of changes in stockholders' equity for the three and six months ended June 30, 2019 and 2018.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. On the Unaudited Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2018, "Purchased oil sales" is a new line item and includes sales related to purchases of oil from third-parties, which were reclassified from "Other income," "Purchased oil expenses" is a new line item and includes expenses related to purchases of oil from third-parties, which were reclassified from "Marketing and plant operating expenses" used in prior reports, and "Transportation and marketing expenses" is a new line item, previously captioned "Marketing and plant operating expenses," but adjusted to exclude both expenses related to plant operating expenses, which were reclassified to "Other expenses," and also purchases of oil from third-parties. Such reclassifications had no impact on our reported total revenues, expenses, net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Cash, Cash Equivalents, and Restricted Cash

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

In thousands	June 30, 2019	December 31, 2018
Cash and cash equivalents	$ 341	$ 38,560
Restricted cash included in other assets	22,198	16,389
Total cash, cash equivalents, and restricted cash shown in the Unaudited Condensed Consolidated Statements of Cash Flows	$ 22,539	$ 54,949

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

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Our prior-year quarterly report on Form 10-Q for the period ended June 30, 2018, filed with the SEC on August 9, 2018, previously disclosed balances of certain U.S. Treasury Notes of $24.6 million and $25.4 million as of January 1, 2018 and June 30, 2018, respectively, that should have been excluded from "Cash, cash equivalents, and restricted cash" on the Consolidated Statements of Cash Flows. Accordingly, "Cash, cash equivalents, and restricted cash" as of January 1, 2018 and June 30, 2018, originally reported as $40.6 million and $41.6 million, respectively, should have been reported as $16.0 million and $16.2 million, respectively. In addition, changes in the U.S. Treasury Notes of $0.8 million during the six months ended June 30, 2018 should have been included in net cash used in investing activities. Accordingly, net cash used in investing activities for the six months ended June 30, 2018, originally reported as $134.1 million, should have been $134.9 million. These revisions had no impact on the Company's financial condition or results of operations for the periods presented.

Net Income per Common Share

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2019	2018	2019	2018
Numerator				
Net income – basic	$ 146,692	$ 30,222	$ 121,018	$ 69,800
Effect of potentially dilutive securities				
Interest on convertible senior notes including amortization of discount, net of tax	548	130	548	539
Net income – diluted	$ 147,240	$ 30,352	$ 121,566	$ 70,339
Denominator				
Weighted average common shares outstanding – basic	452,612	433,467	452,169	413,217
Effect of potentially dilutive securities				
Restricted stock and performance-based equity awards	2,835	8,586	3,301	6,877
Convertible senior notes[1]	11,980	15,112	5,990	34,372
Weighted average common shares outstanding – diluted	467,427	457,165	461,460	454,466

(1) For the three and six months ended June 30, 2019, shares shown under "convertible senior notes" represent the prorated portion of the approximately 90.9 million shares of the Company's common stock issuable upon full conversion of our convertible senior notes (see Note 4, *Long-Term Debt – 2019 Note Exchanges*).

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although time-vesting restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares during the three and six months ended June 30, 2019 and 2018, the nonvested restricted stock and performance-based equity awards are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, and for the shares underlying the convertible senior notes as if the convertible senior notes were converted at the beginning of the 2018 and 2019 periods.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2019	2018	2019	2018
Stock appreciation rights	2,026	2,827	2,059	2,891
Restricted stock and performance-based equity awards	4,998	179	4,790	305

Recent Accounting Pronouncements

Recently Adopted

Leases. Effective January 1, 2019, we adopted Accounting Standards Update ("ASU") 2016-02, *Leases* ("ASU 2016-02"), and ASU 2018-01, *Leases (Topic 842) – Land Easement Practical Expedient for Transition to Topic 842*, using the modified retrospective method with an application date of January 1, 2019. ASU 2016-02 does not apply to mineral leases or leases that convey the right to explore for or use the land on which oil, natural gas, and similar natural resources are contained. We elected the practical expedients provided in the new ASUs that allow historical lease classification of existing leases, allow entities to recognize leases with terms of one year or less in their statement of operations, allow lease and non-lease components to be combined, and carry forward our accounting treatment for existing land easement agreements. The adoption of the new standards resulted in the recognition of $39.1 million of lease assets and $55.8 million of lease liabilities ($16.7 million of which related to previously-existing lease obligations) as of January 1, 2019, in our Unaudited Condensed Consolidated Balance Sheets, but did not materially impact our results of operations and had no impact on our cash flows. The additional lease assets and liabilities recorded on our balance sheet primarily related to our operating leases for office space, as the accounting for our financing leases and pipeline financings was relatively unchanged.

Not Yet Adopted

Financial Instruments – Credit Losses. In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses* ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires the use of a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the amendment using a modified retrospective approach to the first reporting period in which the guidance is effective. The adoption of ASU 2016-13 is currently not expected to have a material effect on our consolidated financial statements.

Fair Value Measurement. In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820) – Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements* ("ASU 2018-13"). ASU 2018-13 adds, modifies, or removes certain disclosure requirements for recurring and nonrecurring fair value measurements based on the FASB's consideration of costs and benefits. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the amendments on changes in unrealized gains and losses for Level 3 fair value measurements, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements, and the narrative description of measurement uncertainty prospectively, and all other amendments should be applied retrospectively to all periods presented. The adoption of ASU 2018-13 is currently not expected to have a material effect on our consolidated financial statements, but may require enhanced footnote disclosures.

Note 2. Revenue Recognition

We record revenue in accordance with Financial Accounting Standards Board Codification ("FASC") Topic 606, *Revenue from Contracts with Customers*. The core principle of FASC Topic 606 is that an entity should recognize revenue for the transfer of goods or services equal to the amount of consideration that it expects to be entitled to receive for those goods or services. Once we have delivered the volume of commodity to the delivery point and the customer takes delivery and possession, we are entitled to payment and we invoice the customer for such delivered production. Payment under most oil and CO_2 contracts is made within a month following product delivery and for natural gas and NGL contracts is generally made within two months following delivery.

Timing of revenue recognition may differ from the timing of invoicing to customers; however, as the right to consideration after delivery is unconditional based on only the passage of time before payment of the consideration is due, upon delivery we record a receivable in "Accrued production receivable" in our Unaudited Condensed Consolidated Balance Sheets, which was $135.7 million and $125.8 million as of June 30, 2019 and December 31, 2018, respectively. The Company enters into purchase transactions with third parties and separate sale transactions with third parties in the Gulf Coast region. Revenues and expenses from these transactions are presented on a gross basis, as we act as a principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser at the delivery point based on the price received from the purchaser.

Disaggregation of Revenue

The following table summarizes our revenues by product type for the three and six months ended June 30, 2019 and 2018:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2019	2018	2019	2018
Oil sales	$ 328,571	$ 373,286	$ 620,536	$ 710,692
Natural gas sales	1,850	2,279	4,462	4,894
CO_2 sales and transportation fees	7,986	6,715	16,556	14,267
Purchased oil sales	2,591	346	2,806	1,403
Total revenues	$ 340,998	$ 382,626	$ 644,360	$ 731,256

Note 3. Leases

We evaluate contracts for leasing arrangements at inception. We lease office space, equipment, and vehicles that have non-cancelable lease terms. Leases with a term of 12 months or less are not recorded on our balance sheet. The table below reflects our operating lease assets and liabilities, which primarily consists of our office leases, and finance lease assets and liabilities:

In thousands	June 30, 2019
Operating leases	
Operating lease right-of-use assets	$ 36,421
Operating lease liabilities - current	$ 6,739
Operating lease liabilities - long-term	45,391
Total operating lease liabilities	$ 52,130
Finance leases	
Other property and equipment	$ 1,736
Accumulated depreciation	(1,465)
Other property and equipment, net	$ 271
Current maturities of long-term debt	$ 233
Long-term debt, net of current portion	59
Total finance lease liabilities	$ 292

The majority of our leases contain renewal options, typically exercisable at our sole discretion. We record right-of-use assets and liabilities based on the present value of lease payments over the initial lease term, unless the option to extend the lease is

reasonably certain, and utilize our incremental borrowing rate based on information available at the lease commencement date. The following weighted average remaining lease terms and discount rates related to our outstanding leases:

	June 30, 2019
Weighted Average Remaining Lease Term	
Operating leases	6.2 years
Finance leases	1.3 years
Weighted Average Discount Rate	
Operating leases	6.8%
Finance leases	2.3%

Lease costs for operating leases or leases with a term of 12 months or less are recognized on a straight-line basis over the lease term. For finance leases, interest on the lease liability and the amortization of the right-of-use asset are recognized separately, with the depreciable life reflective of the expected lease term. We have subleased part of the office space included in our operating leases for which we receive rental payments. The following table summarizes the components of lease costs and sublease income:

In thousands	Income Statement Presentation	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
Operating lease cost	General and administrative expenses	$ 2,412	$ 4,827
Finance lease cost			
Amortization of right-of-use assets	Depletion, depreciation, and amortization	$ 264	$ 1,134
Interest on lease liabilities	Interest expense	8	38
Total finance lease cost		$ 272	$ 1,172
Sublease income	General and administrative expenses	$ 1,331	$ 2,367

Our statement of cash flows included the following activity related to our operating and finance leases:

In thousands	Six Months Ended June 30, 2019
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from operating leases	$ 5,854
Operating cash flows from interest on finance leases	38
Financing cash flows from finance leases	1,217
Right-of-use assets obtained in exchange for lease obligations	
Operating leases	294
Finance leases	—

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

The following table summarizes by year the maturities of our lease liabilities as of June 30, 2019:

In thousands	Operating Leases	Finance Leases
2019	$ 5,063	$ 118
2020	9,874	178
2021	10,042	—
2022	10,259	—
2023	10,300	—
Thereafter	18,537	—
Total minimum lease payments	64,075	296
Less: Amount representing interest	(11,945)	(4)
Present value of minimum lease payments	$ 52,130	$ 292

The following table summarizes by year the remaining non-cancelable future payments under our leases, as accounted for under previous accounting guidance under FASC Topic 840, *Leases*, as of December 31, 2018:

In thousands	Operating Leases
2019	$ 10,690
2020	9,776
2021	10,007
2022	10,223
2023	10,262
Thereafter	18,169
Total minimum lease payments	$ 69,127

Denbury Resources Inc.
Notes to Unaudited Condensed Consolidated Financial Statements

Note 4. Long-Term Debt

The table below reflects long-term debt and capital lease obligations outstanding as of the dates indicated:

In thousands	June 30, 2019	December 31, 2018
Senior Secured Bank Credit Agreement	$ 80,000	$ —
9% Senior Secured Second Lien Notes due 2021	614,919	614,919
9¼% Senior Secured Second Lien Notes due 2022	455,668	455,668
7¾% Senior Secured Second Lien Notes due 2024	528,026	—
7½% Senior Secured Second Lien Notes due 2024	24,638	450,000
6⅜% Convertible Senior Notes due 2024	245,548	—
6⅜% Senior Subordinated Notes due 2021	51,304	203,545
5½% Senior Subordinated Notes due 2022	94,784	314,662
4⅝% Senior Subordinated Notes due 2023	211,695	307,978
Pipeline financings	174,018	180,073
Capital lease obligations	292	5,362
Total debt principal balance	2,480,892	2,532,207
Debt discount[(1)]	(109,072)	—
Future interest payable[(2)]	207,659	250,218
Debt issuance costs	(11,523)	(13,089)
Total debt, net of debt issuance costs and discount	2,567,956	2,769,336
Less: current maturities of long-term debt[(3)]	(101,829)	(105,125)
Long-term debt and capital lease obligations	$ 2,466,127	$ 2,664,211

(1) Consists of discounts related to the issuance during June 2019 of our new 7¾% Senior Secured Second Lien Notes due 2024 (the "7¾% Senior Secured Notes") and new 6⅜% Convertible Senior Notes due 2024 (the "2024 Convertible Senior Notes") of $29.4 million and $79.6 million, respectively (see *2019 Note Exchanges* below) as of June 30, 2019.
(2) Future interest payable represents most of the interest due over the terms of our 9% Senior Secured Second Lien Notes due 2021 (the "2021 Senior Secured Notes") and 9¼% Senior Secured Second Lien Notes due 2022 (the "2022 Senior Secured Notes") and has been accounted for as debt in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*.
(3) Our current maturities of long-term debt as of June 30, 2019 include $85.7 million of future interest payable related to the 2021 Senior Secured Notes and 2022 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 senior secured, convertible senior, and senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI, and the guarantees of the notes are full and unconditional and joint and several; any subsidiaries of DRI that are not subsidiary guarantors of such notes are minor subsidiaries.

Senior Secured Bank Credit Facility

In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (as amended, the "Bank Credit Agreement"), which has been amended periodically since that time. The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2021, provided that the maturity date may occur earlier (between February 2021 and August 2021) if the 2021 Senior Secured Notes due in May 2021 or 6⅜% Senior Subordinated Notes due in August 2021, respectively, are not repaid or refinanced by each of their respective maturity dates. As part of our spring 2019 semiannual redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $615 million, with the next such redetermination being scheduled for November 2019. 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

under the Bank Credit Agreement was 5.1% as of June 30, 2019. We incur a commitment fee of 0.50% on the undrawn portion of the aggregate lender commitments under the Bank Credit Agreement.

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

- A Consolidated Total Debt to Consolidated EBITDAX covenant, with such ratio not to exceed 5.25 to 1.0 through December 31, 2020, and 4.50 to 1.0 thereafter;
- A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 2.5 to 1.0. Only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;
- A minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- A requirement to maintain a current ratio of 1.0 to 1.0.

As of June 30, 2019, we were in compliance with all debt covenants under the Bank Credit Agreement. The above description of our Bank Credit Agreement and defined terms are contained in the Bank Credit Agreement and the amendments thereto.

2019 Note Exchanges

During June 2019, we closed a series of debt exchanges to extend the maturities of our outstanding long-term debt and reduce our debt principal. As part of these transactions, we exchanged a total of $468.4 million aggregate principal amount of our then existing senior subordinated notes for $102.6 million aggregate principal amount of new 7¾% Senior Secured Notes, $245.5 million aggregate principal amount of new 2024 Convertible Senior Notes and $120.0 million of cash. The exchanged subordinated notes consisted of $152.2 million aggregate principal amount of our 6⅜% Senior Subordinated Notes due 2021, $219.9 million aggregate principal amount of our 5½% Senior Subordinated Notes due 2022 and $96.3 million aggregate principal amount of our 4⅝% Senior Subordinated Notes due 2023. In addition, we also exchanged $425.4 million of 7½% Senior Secured Second Lien Notes due 2024 (the "7½% Senior Secured Notes") for $425.4 million aggregate principal amount of 7¾% Senior Secured Notes.

In July 2019, we closed transactions to exchange an additional$4.0 million aggregate principal amount of 7½% Senior Secured Notes for $3.8 million aggregate principal amount of 7¾% Senior Secured Notes.

In accordance with FASC 470-50, *Modifications and Extinguishments*, the June 2019 exchange of our existing senior subordinated notes was accounted for as a debt extinguishment. Therefore, our new 7¾% Senior Secured Notes and new 2024 Convertible Senior Notes were recorded on our balance sheet at fair market value based upon initial trading prices following their issuance, resulting in a discount to their principal amount of $22.6 million and $79.9 million, respectively. These debt discounts will be amortized as interest expense over the terms of these notes. As a result, we recognized a noncash gain on debt extinguishment, net of transaction costs, totaling $100.3 million for the three and six months ended June 30, 2019, in our Unaudited Condensed Consolidated Statements of Operations.

Separately, the exchange of our existing senior secured second lien notes was accounted for as a modification of those notes. Therefore, no gain or loss was recognized, and previously deferred debt issuance costs of $6.9 million were treated as a discount to the principal amount of the new 7¾% Senior Secured Notes, which discount will be amortized as interest expense over the term of these notes.

7¾% Senior Secured Second Lien Notes due 2024

As part of the notes exchanges discussed above, in June 2019 we issued $528.0 million of 7¾% Senior Secured Notes in connection with exchanges with certain holders of the Company's outstanding senior subordinated notes and existing 7½% Senior Secured Notes (see *2019 Note Exchanges* above). The 7¾% Senior Secured Notes, which carry a stated interest rate of 7.75% per annum, were recorded at approximately 94% of their principal amount in accordance with FASC 470-50, *Modifications and Extinguishments*, which equates to an effective yield to maturity of approximately 9.39%. Interest on the 7¾% Senior Secured Notes is payable semiannually in arrears on February 15 and August 15 of each year, and mature on February 15, 2024. We may redeem the 7¾% Senior Secured Notes in whole or in part at our option beginning August 15, 2020, at a redemption price of 103.875% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture governing the 7¾ % Senior Secured Notes. Prior to August 15, 2020, we may at our option redeem up to an aggregate of 35% of the principal amount of the 7¾% Senior Secured Notes at a price of 107.75% of par with the proceeds of certain equity offerings. In addition, at any

time prior to August 15, 2020, we may redeem the 7¾% Senior Secured Notes in whole or in part at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 7¾% Senior Secured Notes are not subject to any sinking fund requirements.

The 7¾% Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

6⅜% Convertible Senior Notes due 2024

As part of the notes exchanges discussed above, in June 2019 we issued $245.5 million of 2024 Convertible Senior Notes in connection with exchanges with certain holders of the Company's existing senior subordinated notes (see *2019 Note Exchanges* above). The 2024 Convertible Senior Notes, which carry a stated interest rate of 6.375% per annum, were recorded at approximately 67% of their principal amount in accordance with FASC 470-50, *Modifications and Extinguishments*, which equates to an effective yield to maturity of approximately 15.31%. Interest on the 2024 Convertible Senior Notes is payable semiannually in arrears on June 30 and December 30 of each year, beginning in December 2019, and mature on December 31, 2024. We do not have the right to redeem the 2024 Convertible Senior Notes prior to their maturity. The 2024 Convertible Senior Notes are convertible into shares of our common stock at any time, at the option of the holders, at a rate of 370 shares of common stock per $1,000 principal amount of 2024 Convertible Senior Notes, which is equivalent to up to approximately 90.9 million shares of the Company's common stock, subject to customary adjustments to the conversion rate and threshold price with respect to, among other things, stock dividends and distributions, mergers and reclassifications. The 2024 Convertible Senior Notes will be automatically converted into shares of common stock at this rate if the volume weighted average trading price of the Company's common stock equals or exceeds the threshold price, which initially is $2.43 per share, for 10 trading days in any period of 15 consecutive trading days, subject to satisfaction of certain other conditions. Additionally, the Company may, based on a determination of its Board of Directors that such changes are in the best interests of the Company, and subject to certain limitations, increase the conversion rate. Any such conversion rate increase would cause a proportional decrease in the threshold price for mandatory conversions, and thereby would enable the Company to require a mandatory conversion into common stock at a lower price than the initial or then-prevailing threshold price.

Note 5. Commodity Derivative Contracts

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

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

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement (or affiliates of such lenders). As of June 30, 2019, 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, 2019, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices ($/Bbl)				
				Weighted Average Price			
Months	Index Price	Volume (Barrels per day)	Range[1]	Swap	Sold Put	Floor	Ceiling
Oil Contracts:							
2019 Fixed-Price Swaps							
July – Dec	Argus LLS	13,000	$ 60.00 – 74.90	$ 64.69	$ —	$ —	$ —
2019 Three-Way Collars[2]							
July – Dec	NYMEX	22,000	$ 55.00 – 75.45	$ —	$ 48.55	$ 56.55	$ 69.17
July – Dec	Argus LLS	5,500	62.00 – 86.00	—	54.73	63.09	79.93
2020 Fixed-Price Swaps							
Jan – Dec	NYMEX	2,000	$ 60.00 – 61.00	$ 60.59	$ —	$ —	$ —
Jan – Dec	Argus LLS	4,000	60.72 – 64.26	62.41	—	—	—
2020 Three-Way Collars[2]							
Jan – June	NYMEX	12,000	$ 55.00 – 82.65	$ —	$ 48.89	$ 58.49	$ 65.57
Jan – June	Argus LLS	4,500	62.50 – 87.10	—	53.89	63.89	72.55
July – Dec	NYMEX	10,000	55.00 – 82.65	—	49.05	58.58	65.81
July – Dec	Argus LLS	2,500	64.00 – 87.10	—	54.40	64.40	76.59

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

(2) 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. As of June 30, 2019, 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 $150 thousand in the fair value of these instruments as of June 30, 2019.

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, 2019				
Assets				
Oil derivative contracts – current	$ —	$ 19,927	$ 4,520	$ 24,447
Oil derivative contracts – long-term	—	7,935	1,553	9,488
Total Assets	$ —	$ 27,862	$ 6,073	$ 33,935
Liabilities				
Oil derivative contracts – current	$ —	$ (1,912)	$ —	$ (1,912)
Oil derivative contracts – long-term	—	(22)	—	(22)
Total Liabilities	$ —	$ (1,934)	$ —	$ (1,934)
December 31, 2018				
Assets				
Oil derivative contracts – current	$ —	$ 81,621	$ 11,459	$ 93,080
Oil derivative contracts – long-term	—	2,030	2,165	4,195
Total Assets	$ —	$ 83,651	$ 13,624	$ 97,275

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

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the three and six months ended June 30, 2019 and 2018:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2019	2018	2019	2018
Fair value of Level 3 instruments, beginning of period	$ 3,686	$ —	$ 13,624	$ —
Fair value gains (losses) on commodity derivatives	2,720	(1,168)	(6,360)	(1,168)
Receipts on settlements of commodity derivatives	(333)	—	(1,191)	—
Fair value of Level 3 instruments, end of period	$ 6,073	$ (1,168)	$ 6,073	$ (1,168)
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	$ 2,387	$ (1,168)	$ (1,240)	$ (1,168)

We utilize an income approach to value our Level 3 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 6/30/2019 (in thousands)	Valuation Technique	Unobservable Input	Volatility Range
Oil derivative contracts	$ 6,073	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after June 30, 2019	20.4% – 34.1%

Other Fair Value Measurements

The carrying value of our loans under our Bank Credit Agreement approximate fair value, as they are subject to short-term floating interest rates that approximate the rates available to us for those periods. We use a market approach to determine the fair value of our fixed-rate long-term debt using observable market data. The fair values of our senior secured second lien notes, convertible senior notes, and senior subordinated notes are based on quoted market prices, which are considered Level 1 measurements under the fair value hierarchy. The estimated fair value of the principal amount of our debt as of June 30, 2019 and December 31, 2018, excluding pipeline financing and capital lease obligations, was $1,935.6 million and $1,886.1 million, respectively. We have other financial instruments consisting primarily of cash, cash equivalents, U.S. Treasury Notes, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 7. Commitments and Contingencies

Litigation

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. We are also subject to audits for various taxes (income, sales and use, and severance) in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. We accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC ("APMTG"). The helium supply contract provides for the delivery of a minimum contracted quantity of helium, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are specified in the contract at up to $8.0 million per contract year and are capped at an aggregate of $46.0 million over the term of the contract.

As the gas processing facility has been shut-in since mid-2014 due to significant technical issues, we have not been able to supply helium under the helium supply contract. In a case filed in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, APMTG claimed multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company claimed that its contractual obligations were excused by virtue of events that fall within the force majeure provisions in the helium supply contract.

On March 11, 2019, the trial court entered a final judgment that a force majeure condition did exist, but the Company's performance was excused by the force majeure provisions of the contract for only a 35-day period in 2014, and as a result the Company should pay APMTG liquidated damages and interest thereon for those time periods from contract commencement to the close of evidence (November 29, 2017) when the Company's performance was not excused as provided in the contract. The Company has filed a notice of appeal of the trial court's ruling to the Wyoming Supreme Court, the results of which cannot be predicted at this time.

The Company's position continues to be that its contractual obligations have been and continue to be excused by events that fall within the force majeure provisions in the helium supply contract. The Company intends to continue to vigorously defend its position and pursue all of its rights.

Absent reversal of the trial court's ruling on appeal, the Company anticipates total liquidated damages would equal the $46.0 million aggregate cap under the helium supply contract (including $14.2 million of liquidated damages for the contract years ending July 31, 2018 and July 31, 2019) plus $4.2 million of associated costs (through June 30, 2019), for a total of $50.2 million, included in "Other liabilities" in our Unaudited Condensed Consolidated Balance Sheets as of June 30, 2019.

Note 8. Subsequent Event

On July 17, 2019, the Compensation Committee of our Board of Directors made our annual grant of long-term incentive awards, consisting of 9,115,746 shares of restricted stock and 3,759,051 restricted stock units which are to be settled solely in cash, to certain employees under our 2004 Omnibus Stock and Incentive Plan. The closing stock price of Denbury's common stock on July 17, 2019 was $1.17 per share; however, the Compensation Committee utilized a stock price floor of $2.25 per share in determining the total number of shares of restricted stock granted. In addition, the amount of cash for which the restricted stock units can be settled is capped at no more than two times the grant date value of the restricted stock units. The awards generally vest one-third per year over a three-year period.

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

The following discussion and analysis should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and Notes thereto included herein and our Consolidated Financial Statements and Notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2018 (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. Changes in oil prices impact all aspects of our business; most notably our cash flows from operations, revenues, and capital allocation and budgeting decisions. Excluding the impact of derivative settlements, our average realized oil price was $59.39 per Bbl during the first half of 2019, compared to $66.29 per Bbl during the first half of 2018. Including the impact of derivative settlements, our average realized oil price was $60.03 per Bbl during the first half of 2019, compared to $58.07 per Bbl in the first half of 2018. With our continued focus on improving the Company's financial position and preserving liquidity, we have based our 2019 budget on a flat $50 oil price, and our 2019 capital spending has been budgeted in a range of $240 million to $260 million, excluding capitalized interest and acquisitions, which is roughly a 23% decrease from our 2018 capital spending levels. Based on recent oil price futures and our projections for the remainder of 2019, we estimate that our cash flows from operations will be significantly higher than our capital expenditures and result in Denbury generating significant excess cash flow during 2019. Also, we have hedged approximately 70% of our estimated second half 2019 production in order to provide a greater level of certainty in our 2019 cash flow. Based on our strong production performance during the first half of 2019 and expectations for the remainder of 2019, we currently anticipate that our 2019 production will average between 57,000 and 59,500 BOE/d, compared to our previous estimate of 56,000 and 60,000 BOE/d. Additional information concerning our 2019 budget and plans is included below under *Capital Resources and Liquidity – Overview*.

Operating Highlights. We recognized net income of $146.7 million, or $0.32 per diluted common share, during the second quarter of 2019, compared to net income of $30.2 million, or $0.07 per diluted common share, during the second quarter of 2018. The primary drivers of these comparative period changes in our operating results were the following:

- Commodity derivatives expense decreased by $121.0 million ($24.8 million of income in the current-year period compared to $96.2 million of expense in the prior-year period.) This decrease was primarily due to a change in noncash fair value adjustments of $67.8 million ($26.3 million of income in the current-year period compared to $41.4 million of expense in the prior-year period) and a $53.2 million decrease in payments on derivative contracts.
- Noncash gain on debt extinguishment, net of transaction costs, of $100.3 million in the current-year period related to our June 2019 notes exchanges (see *2019 Note Exchanges* below).
- Oil and natural gas revenues in the second quarter of 2019 decreased by $45.1 million, or 12%, principally driven by a 9% decrease in realized oil prices.

We generated $148.6 million of cash flow from operating activities in the second quarter of 2019, relatively unchanged from the $154.0 million generated during the second quarter of 2018, but $84.2 million higher than the $64.4 million of cash flow generated in the first quarter of 2019.

2019 Note Exchanges. During June 2019, we closed a series of debt exchanges to extend the maturities of our outstanding long-term debt and reduce our debt principal. As part of these transactions, we exchanged a total of $468.4 million aggregate principal amount of our then existing senior subordinated notes for $102.6 million aggregate principal amount of our new 7¾% Senior Secured Second Lien Notes due 2024 (the "7¾% Senior Secured Notes"), $245.5 million aggregate principal amount of our new 6⅜% Convertible Senior Notes due 2024 (the "2024 Convertible Senior Notes") and $120.0 million of cash. The exchanged

subordinated notes consisted of $152.2 million aggregate principal amount of our 6⅜% Senior Subordinated Notes due 2021, $219.9 million aggregate principal amount of our 5½% Senior Subordinated Notes due 2022 and $96.3 million aggregate principal amount of our 4⅝% Senior Subordinated Notes due 2023. In addition, as part of creating a more liquid series of secured second lien debt due in 2024, we also exchanged $425.4 million of 7½% Senior Secured Second Lien Notes due 2024 (the "7½% Senior Secured Notes") for $425.4 million aggregate principal amount of 7¾% Senior Secured Notes.

In July 2019, we closed transactions to exchange an additional $4.0 million aggregate principal amount of 7½% Senior Secured Notes for $3.8 million aggregate principal amount of 7¾% Senior Secured Notes. The table below details the changes in our debt principal balances from March 31, 2019 to June 30, 2019, for those notes impacted by the June 2019 note exchanges discussed above, and includes the impact of the additional $4.0 million aggregate principal amount of 7½% Senior Secured Notes exchanged in July:

In thousands	March 31, 2019	Principal Exchanged (excluding cash)	June 30, 2019
Notes Exchanged			
6⅜% Senior Subordinated Notes due 2021	$ 203,545	$ (152,241)	$ 51,304
5½% Senior Subordinated Notes due 2022	314,662	(219,878)	94,784
4⅝% Senior Subordinated Notes due 2023	307,978	(96,283)	211,695
7½% Senior Secured Second Lien Notes due 2024	450,000	(429,359)	20,641
New Notes Issued			
7¾% Senior Secured Second Lien Notes due 2024	—	531,821	531,821
6⅜% Convertible Senior Notes due 2024	—	245,548	245,548
	$ 1,276,185	$ (120,392) (1)	$ 1,155,793

(1) Primarily represents cash paid in the debt exchange transactions.

In accordance with Financial Accounting Standards Board Codification ("FASC") 470-50, *Modifications and Extinguishments*, the June 2019 exchange of our existing senior subordinated notes was accounted for as a debt extinguishment. Therefore, our new 7¾% Senior Secured Notes and new 2024 Convertible Senior Notes were recorded on our balance sheet at fair market value based upon initial trading prices following their issuance, resulting in a discount to their principal amount of $22.6 million and $79.9 million, respectively. These debt discounts will be amortized as interest expense over the terms of these notes. As a result, we recognized a noncash gain on debt extinguishment, net of transaction costs, totaling $100.3 million for the three and six months ended June 30, 2019, in our Unaudited Condensed Consolidated Statements of Operations.

Separately, the exchange of our existing senior secured second lien notes was accounted for as a modification of those notes. Therefore, no gain or loss was recognized, and previously deferred debt issuance costs of $6.9 million were treated as a discount to the principal amount of the new 7¾% Senior Secured Notes, which discount will be amortized as interest expense over the term of these notes. Based on the combined debt discount of $109.4 million recorded in connection with the note exchanges, future interest expense reflected in our Unaudited Condensed Consolidated Statements of Operations will be higher than the actual cash interest payments on the 7¾% Senior Secured Notes and 2024 Convertible Senior Notes (see *Results of Operations – Interest and Financing Expenses* for further discussion).

July 2019 Citronelle Field Divestiture. On July 1, 2019, we closed the sale of one of our mature Gulf Coast fields, Citronelle Field, which contributed 406 BOE/d to total Company production during the second quarter of 2019, for $10 million. The sale had an effective date of May 1, 2019.

Exploitation Drilling Update. During the second quarter of 2019, we tested our first horizontal well at Conroe Field, which achieved a high oil cut and a peak production rate over 200 BOE/d. We currently plan to drill an additional well in 2020 in an adjacent fault block that considers what we have learned from the first well. We also tested the Cotton Valley interval at Tinsley Field during the second quarter, and while we were pleased with the 2.5 MMcf/d gas rate and high liquids yield, these test results, coupled with current commodity prices, would make a standalone development of the Lower Cotton Valley below our investment

threshold. We continue to work plans to test uphole intervals, which we believe to contain higher liquid content, and will then determine the best next steps, which could include self-development or potentially farming out the discovery to a third party. We continue to evaluate exploitation opportunities in additional horizons underlying the existing CO_2 EOR flood at Tinsley Field, as well as within oil-bearing formations at Conroe Field. At Cedar Creek Anticline, we currently have plans to drill two additional Mission Canyon wells and a Charles B follow-up well in the second half of 2019.

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 six months ended June 30, 2019, we generated cash flow from operations of $213.0 million, after giving effect to $50.8 million of cash outflows for working capital changes primarily related to payments during the first half of the year for ad valorem tax payments, accrued interest on our debt and accrued compensation. As of June 30, 2019, we had $80.0 million of outstanding borrowings on our $615 million senior secured bank credit facility, compared to no outstanding borrowings as of December 31, 2018 and March 31, 2019, leaving us with $480.5 million of borrowing base availability after consideration of $54.5 million of currently outstanding letters of credit. Based on our current 2019 projections using recent oil price futures, we expect to generate free cash flow sufficient to pay down the $80 million borrowed on our senior secured bank credit facility by the end of 2019, to the extent we choose to do so.

We have historically tried to limit our development capital spending to be roughly the same as, or less than, our cash flow from operations, and our 2019 cash flows from operations are currently expected to significantly exceed our planned $240 million to $260 million of development capital expenditures for the year.

As an additional source of potential liquidity, the Company has been engaged in two asset sale processes. In the first process, we have been actively marketing for sale surface land with no active oil and gas operations around our Conroe and Webster fields. During the second quarter of 2019, we entered into new contracts for $38 million, bringing the aggregate amount of land sold or under contract to $52 million as of June 30, 2019. During 2018, we completed approximately $5 million of land sales and currently have signed agreements for another $47 million, of which we expect to close $15 million in the second half of 2019, plus approximately $32 million under contract that provide for purchase price payments to begin by mid-2021, subject to a number of conditions. We remain focused on a strategy that we believe will ultimately yield the highest value for the remaining land, and we expect significant additional value of the remaining parcels not yet sold or under contract to be realized over the next two years. In the second process, in 2018 we began the process of portfolio optimization through the marketing of mature fields located in Mississippi and Louisiana and Citronelle Field in Alabama. In connection with this process, we completed the sale of Lockhart Crossing Field for net proceeds of approximately $4 million during the third quarter of 2018 and closed the sale of Citronelle Field for approximately $10 million during July 2019. The pace and outcome of any sales of the remaining assets cannot be predicted at this time, but their successful completion could provide additional liquidity for financial or operational uses.

Over the last several years, we have been keenly focused on reducing leverage and improving the Company's financial condition. In total, we have reduced our outstanding debt principal by $1.1 billion between December 31, 2014 and June 30, 2019, primarily through debt exchanges, opportunistic open market debt repurchases, and the conversion in the second quarter of 2018 of all of our then outstanding convertible senior notes into common stock. Our leverage metrics have improved considerably over the past year, due primarily to our cost reduction efforts, improvement in oil prices and our overall reduction in debt. In conjunction with our continuing efforts to improve the Company's balance sheet, we plan to assess, and may engage in, potential debt reduction and/or maturity extension transactions of various types, with a primary focus on our 2021 and 2022 debt maturities, balanced with maintaining liquidity.

Senior Secured Bank Credit Facility. In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (as amended, the "Bank Credit Agreement"), which has been amended periodically since that time. The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2021, provided that the maturity date may occur earlier (between February 2021 and August 2021) if the 9% Senior Secured Second Lien Notes due in May 2021 (the "2021 Senior Secured Notes") or 6⅜% Senior Subordinated Notes due in August 2021, respectively, are not repaid or refinanced by each of their respective maturity dates. As part of our spring 2019 semiannual borrowing base redetermination, the borrowing base and lender commitments for our Bank Credit Agreement were reaffirmed at $615 million, with the next such redetermination scheduled for November 2019. The Bank Credit Agreement contains certain financial performance covenants through the maturity of the facility, including the following:

- A Consolidated Total Debt to Consolidated EBITDAX covenant, with such ratio not to exceed 5.25 to 1.0 through December 31, 2020, and 4.50 to 1.0 thereafter;
- A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 2.5 to 1.0. Only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;
- A minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- A requirement to maintain a current ratio of 1.0 to 1.0.

Under these financial performance covenant calculations, as of June 30, 2019, our ratio of consolidated total debt to consolidated EBITDAX was 4.14 to 1.0 (with a maximum permitted ratio of 5.25 to 1.0), our consolidated senior secured debt to consolidated EBITDAX was 0.13 to 1.0 (with a maximum permitted ratio of 2.5 to 1.0), our ratio of consolidated EBITDAX to consolidated interest charges was 3.12 to 1.0 (with a required ratio of not less than 1.25 to 1.0), and our current ratio was 2.64 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 6, 2019, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our financial performance covenants during the foreseeable future.

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

2019 Note Exchanges. Through a series of exchange transactions completed on June 19, 2019 (see *Overview – 2019 Note Exchanges* above), we reduced our debt principal balance by $120 million and extended the maturities of $348.4 million aggregate principal amount of our existing debt by exchanging a portion of our 6⅜% Senior Subordinated Notes due 2021, 5½% Senior Subordinated Notes due 2022 and 4⅝% Senior Subordinated Notes due 2023 for 7¾% Senior Secured Notes, 2024 Convertible Senior Notes and cash. In addition to extending maturities of a portion of our existing debt, the exchange transactions could contribute to debt reduction of $245.5 million if all of the 2024 Convertible Senior Notes convert to Company common stock (based upon issuance of up to 90,852,760 shares at the current conversion rate of 370 shares of common stock per $1,000 principal amount for such notes).

Capital Spending. We currently anticipate that our full-year 2019 capital spending, excluding capitalized interest and acquisitions, will be approximately $240 million to $260 million. Although we currently have no plans to adjust our anticipated capital spending for 2019, we continually evaluate our expected cash flows and capital expenditures throughout the year and could adjust capital expenditures if our cash flows were to meaningfully change. Capitalized interest is currently estimated at between $30 million and $40 million for 2019. The 2019 capital budget, excluding capitalized interest and acquisitions, provides for approximate spending as follows:

- $100 million allocated for tertiary oil field expenditures;
- $70 million allocated for other areas, primarily non-tertiary oil field expenditures including exploitation;
- $30 million to be spent on CO_2 sources and pipelines; and
- $50 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Based upon our currently forecasted levels of production and costs, commodity hedges in place, and current oil commodity futures prices, we intend to fund our development capital spending with cash flow from operations. If prices were to decrease or changes in operating results were to cause a reduction in anticipated 2019 cash flows significantly below our currently forecasted operating cash flows, we would likely reduce our capital expenditures. If we reduce our capital spending due to lower cash flows, any sizeable reduction would likely lower our anticipated production levels in future years.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
In thousands	2019	2018
Capital expenditure summary		
Tertiary oil fields	$ 54,786	$ 64,086
Non-tertiary fields	36,554	32,739
Capitalized internal costs[(1)]	24,214	22,747
Oil and natural gas capital expenditures	115,554	119,572
CO_2 pipelines, sources and other	22,465	9,648
Capital expenditures, before acquisitions and capitalized interest	138,019	129,220
Acquisitions of oil and natural gas properties	97	21
Capital expenditures, before capitalized interest	138,116	129,241
Capitalized interest	18,772	17,303
Capital expenditures, total	$ 156,888	$ 146,544

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

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

Our commitments and obligations consist of those detailed as of December 31, 2018, in our Form 10-K under *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commitments and Obligations*.

RESULTS OF OPERATIONS

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

Operating Results Table

Certain of our operating results and statistics for the comparative three and six months ended June 30, 2019 and 2018 are included in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-share and unit data	2019	2018	2019	2018
Operating results				
Net income	$ 146,692	$ 30,222	$ 121,018	$ 69,800
Net income per common share – basic	0.32	0.07	0.27	0.17
Net income per common share – diluted	0.32	0.07	0.26	0.15
Net cash provided by operating activities	148,634	153,999	213,000	245,626
Average daily production volumes				
Bbls/d	58,034	60,109	57,726	59,236
Mcf/d	10,111	11,314	10,467	11,607
BOE/d[1]	59,719	61,994	59,470	61,171
Operating revenues				
Oil sales	$ 328,571	$ 373,286	$ 620,536	$ 710,692
Natural gas sales	1,850	2,279	4,462	4,894
Total oil and natural gas sales	$ 330,421	$ 375,565	$ 624,998	$ 715,586
Commodity derivative contracts[2]				
Receipt (payment) on settlements of commodity derivatives	$ (1,549)	$ (54,770)	$ 6,657	$ (88,127)
Noncash fair value gains (losses) on commodity derivatives[3]	26,309	(41,429)	(65,274)	(56,897)
Commodity derivatives income (expense)	$ 24,760	$ (96,199)	$ (58,617)	$ (145,024)
Unit prices – excluding impact of derivative settlements				
Oil price per Bbl	$ 62.22	$ 68.24	$ 59.39	$ 66.29
Natural gas price per Mcf	2.01	2.21	2.35	2.33
Unit prices – including impact of derivative settlements[2]				
Oil price per Bbl	$ 61.92	$ 58.23	$ 60.03	$ 58.07
Natural gas price per Mcf	2.01	2.21	2.35	2.33
Oil and natural gas operating expenses				
Lease operating expenses	$ 117,932	$ 120,384	$ 243,355	$ 238,740
Transportation and marketing expenses	11,236	10,062	22,009	20,555
Production and ad valorem taxes	23,526	25,363	45,560	50,395
Oil and natural gas operating revenues and expenses per BOE				
Oil and natural gas revenues	$ 60.80	$ 66.57	$ 58.06	$ 64.63
Lease operating expenses	21.70	21.34	22.61	21.56
Transportation and marketing expenses	2.07	1.78	2.04	1.86
Production and ad valorem taxes	4.33	4.50	4.23	4.55
CO_2 sources – revenues and expenses				
CO_2 sales and transportation fees	$ 7,986	$ 6,715	$ 16,556	$ 14,267
CO_2 discovery and operating expenses	(581)	(500)	(1,137)	(962)
CO_2 revenue and expenses, net	$ 7,405	$ 6,215	$ 15,419	$ 13,305

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas ("BOE").
(2) See also *Commodity Derivative Contracts* below and *Item 3. Quantitative and Qualitative Disclosures about Market Risk* for information concerning our derivative transactions.

(3) 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 $1.5 million for the three months ended June 30, 2019 and receipts on settlements of $6.7 million for the six months ended June 30, 2019, compared to payments on settlements of $54.8 million and $88.1 million for the three and six months ended June 30, 2018, 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 2018 and for the first and second quarters of 2019 is shown below:

	Average Daily Production (BOE/d)					
Operating Area	First Quarter 2018	Second Quarter 2018	Third Quarter 2018	Fourth Quarter 2018	First Quarter 2019	Second Quarter 2019
Tertiary oil production						
Gulf Coast region						
Delhi	4,169	4,391	4,383	4,526	4,474	4,486
Hastings	5,704	5,716	5,486	5,480	5,539	5,466
Heidelberg	4,445	4,330	4,376	4,269	3,987	4,082
Oyster Bayou	5,056	4,961	4,578	4,785	4,740	4,394
Tinsley	6,053	5,755	5,294	5,033	4,659	4,891
West Yellow Creek	57	142	240	375	436	586
Mature properties[1]	6,726	6,725	6,612	6,748	6,479	6,448
Total Gulf Coast region	32,210	32,020	30,969	31,216	30,314	30,353
Rocky Mountain region						
Bell Creek	4,050	4,010	3,970	4,421	4,650	5,951
Salt Creek	2,002	2,049	2,274	2,107	2,057	2,078
Other	—	—	6	20	52	41
Total Rocky Mountain region	6,052	6,059	6,250	6,548	6,759	8,070
Total tertiary oil production	38,262	38,079	37,219	37,764	37,073	38,423
Non-tertiary oil and gas production						
Gulf Coast region						
Mississippi	875	901	1,038	1,023	1,034	1,025
Texas	4,386	4,947	4,533	4,319	4,345	4,243
Other	44	—	5	6	10	6
Total Gulf Coast region	5,305	5,848	5,576	5,348	5,389	5,274
Rocky Mountain region						
Cedar Creek Anticline	14,437	15,742	14,208	14,961	14,987	14,311
Other	1,485	1,490	1,409	1,343	1,313	1,305
Total Rocky Mountain region	15,922	17,232	15,617	16,304	16,300	15,616
Total non-tertiary production	21,227	23,080	21,193	21,652	21,689	20,890
Total continuing production	59,489	61,159	58,412	59,416	58,762	59,313
Property sales						
Citronelle[2]	387	388	416	451	456	406
Lockhart Crossing[3]	462	447	353	—	—	—
Total production	60,338	61,994	59,181	59,867	59,218	59,719

(1) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields.
(2) Includes production from Citronelle Field sold in July 2019.
(3) Includes production from Lockhart Crossing Field sold in the third quarter of 2018.

Total continuing production during the second quarter of 2019 averaged 59,313 BOE/d, including 38,423 Bbls/d, or 65%, from tertiary properties and 20,890 BOE/d from non-tertiary properties. Total continuing production excludes production from Citronelle Field sold in July 2019 and, for prior-year periods, excludes production from Lockhart Crossing Field sold in the third

quarter of 2018. This total continuing production level represents an increase of 551 BOE/d (1%) compared to total production levels in the first quarter of 2019 primarily due to continued response from Bell Creek's phase 5 development and a decrease of 1,846 BOE/d (3%) compared to second quarter of 2018 continuing production levels primarily due to lower production from Tinsley Field and Cedar Creek Anticline, with the decline at Cedar Creek Anticline due in part to timing of drilling new exploitation wells. Our production during the three and six months ended June 30, 2019 was 97% oil, consistent with oil production during the prior-year periods. We currently expect our third quarter 2019 production will be lower than the second quarter due to an extended period of planned maintenance at our primary Rocky Mountain region CO_2 source impacting Bell Creek Field production, seasonal temperature effects in the Gulf Coast region, and the July 1, 2019 sale of Citronelle Field.

Oil and Natural Gas Revenues

Our oil and natural gas revenues during the three and six months ended June 30, 2019 decreased 12% and 13%, respectively, compared to these revenues for the same periods in 2018. The changes in our oil and natural gas revenues are due to changes in production quantities and realized commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

	Three Months Ended June 30, 2019 vs. 2018		Six Months Ended June 30, 2019 vs. 2018	
In thousands	Decrease in Revenues	Percentage Decrease in Revenues	Decrease in Revenues	Percentage Decrease in Revenues
Change in oil and natural gas revenues due to:				
Decrease in production	$ (13,782)	(4)%	$ (19,892)	(3)%
Decrease in realized commodity prices	(31,362)	(8)%	(70,696)	(10)%
Total decrease in oil and natural gas revenues	$ (45,144)	(12)%	$ (90,588)	(13)%

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, 2019 and 2018:

	Three Months Ended March 31,		Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018	2019	2018
Average net realized prices						
Oil price per Bbl	$ 56.50	$ 64.25	$ 62.22	$ 68.24	$ 59.39	$ 66.29
Natural gas price per Mcf	2.68	2.44	2.01	2.21	2.35	2.33
Price per BOE	55.27	62.61	60.80	66.57	58.06	64.63
Average NYMEX differentials						
Gulf Coast region						
Oil per Bbl	$ 4.26	$ 2.05	$ 4.85	$ 1.12	$ 4.55	$ 1.59
Natural gas per Mcf	(0.10)	0.10	0.10	0.04	0.00	0.07
Rocky Mountain region						
Oil per Bbl	$ (2.56)	$ (0.06)	$ (1.48)	$ (0.84)	$ (1.97)	$ (0.39)
Natural gas per Mcf	(0.28)	(0.92)	(1.13)	(1.25)	(0.67)	(1.08)
Total Company						
Oil per Bbl	$ 1.63	$ 1.29	$ 2.35	$ 0.39	$ 2.01	$ 0.87
Natural gas per Mcf	(0.20)	(0.40)	(0.50)	(0.62)	(0.34)	(0.51)

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.

- **Gulf Coast Region**. Our average NYMEX oil differential in the Gulf Coast region was a positive $4.85 per Bbl and a positive $1.12 per Bbl during the second quarters of 2019 and 2018, respectively, and a positive $4.26 per Bbl during the first quarter of 2019. Generally, our Gulf Coast region differentials are positive to NYMEX and highly correlated to the changes in prices of Light Louisiana Sweet crude oil, which have generally strengthened over the past year, although recent Gulf Coast region differentials have somewhat softened.

- **Rocky Mountain Region**. NYMEX oil differentials in the Rocky Mountain region averaged $1.48 per Bbl and $0.84 per Bbl below NYMEX during the second quarters of 2019 and 2018, respectively, and $2.56 per Bbl below NYMEX during the first quarter of 2019. 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. Although our differentials in the Rocky Mountain region have weakened somewhat from a year ago, they have improved from the differentials we experienced in the fourth quarter of 2018 and first quarter of 2019.

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, 2019 and 2018:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2019	2018	2019	2018
Receipt (payment) on settlements of commodity derivatives	$ (1,549)	$ (54,770)	$ 6,657	$ (88,127)
Noncash fair value gains (losses) on commodity derivatives[1]	26,309	(41,429)	(65,274)	(56,897)
Total income (expense)	$ 24,760	$ (96,199)	$ (58,617)	$ (145,024)

(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.

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 2020 using both NYMEX and LLS fixed-price swaps and three-way collars. See Note 5, *Commodity Derivative Contracts*, to the Unaudited Condensed Consolidated Financial Statements for additional details of our outstanding commodity derivative contracts as of June 30, 2019, and Item 3, *Quantitative and Qualitative Disclosures about Market Risk* below for additional discussion. In addition, the following table summarizes our commodity derivative contracts as of August 6, 2019:

		2H 2019	1H 2020	2H 2020
WTI NYMEX Fixed-Price Swaps	Volumes Hedged (Bbls/d)	—	2,000	2,000
	Swap Price[1]	—	$60.59	$60.59
Argus LLS Fixed-Price Swaps	Volumes Hedged (Bbls/d)	13,000	4,500	4,500
	Swap Price[1]	$64.69	$62.29	$62.29
WTI NYMEX 3-Way Collars	Volumes Hedged (Bbls/d)	22,000	12,000	10,000
	Sold Put Price / Floor / Ceiling Price[1][2]	$48.55 / $56.55 / $69.17	$48.89 / $58.49 / $65.57	$49.05 / $58.58 / $65.81
Argus LLS 3-Way Collars	Volumes Hedged (Bbls/d)	5,500	6,000	4,000
	Sold Put Price / Floor / Ceiling Price[1][2]	$54.73 / $63.09 / $79.93	$53.42 / $63.19 / $71.16	$53.50 / $63.16 / $72.99
	Total Volumes Hedged (Bbls/d)	40,500	24,500	20,500

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

Based on current contracts in place and NYMEX oil futures prices as of August 6, 2019, which averaged approximately $53 per Bbl, we currently expect that we would receive cash payments of approximately $30 million during the remainder of 2019 upon settlement of the 2019 contracts, the amount of which is dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our 2019 fixed-price swaps which have weighted average prices of $64.69 per Bbl for LLS hedges and weighted average ceiling prices of our 2019 three-way collars of $69.17 per Bbl and $79.93 per Bbl for NYMEX and LLS hedges, respectively. Changes in commodity prices, expiration of contracts, and new commodity contracts entered into cause fluctuations in the estimated fair value of our oil derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations.

Production Expenses

Lease Operating Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2019	2018	2019	2018
Total lease operating expenses	$ 117,932	$ 120,384	$ 243,355	$ 238,740
Total lease operating expenses per BOE	$ 21.70	$ 21.34	$ 22.61	$ 21.56

Total lease operating expenses decreased $2.5 million (2%) on an absolute-dollar basis, but increased $0.36 (2%) on a per-BOE basis, during the three months ended June 30, 2019, compared to the same prior-year period. The decrease on an absolute-dollar basis was primarily due to lower power and fuel costs and lower CO_2 expense due to a decrease in oil prices and transportation rates, partially offset by an increase in contract labor for repair & maintenance activities primarily at Cedar Creek Anticline ("CCA"), with the per-BOE change further impacted by the decline in total production between the second quarters of 2018 and 2019. Lease operating expenses for the six months ended June 30, 2019 increased $4.6 million (2%) on an absolute dollar basis, or $1.05 (5%) on a per-BOE basis, compared to levels in the same period in 2018, primarily due to an increase in contract labor primarily at CCA and higher CO_2 expense due to an increase in injection volumes and new floods and expansion areas moving into the production stage, resulting in costs being expensed versus capitalized, partially offset by lower power and fuel costs. Compared to the first quarter of 2019, lease operating expenses in the second quarter of 2019 decreased $7.5 million (6%) on an absolute-dollar basis or $1.83 (8%) on a per-BOE basis primarily due to lower CO_2 expense due to lower utilization of industrial-sourced CO_2 in our Gulf Coast region and lower power and fuel costs.

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 2019 and 2018, approximately 56% and 49%, respectively, of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us (our net revenue interest). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties for CO_2, our average cost of CO_2 was approximately $0.33 per Mcf during the second quarter of 2019, including taxes paid on CO_2 production but excluding depletion, depreciation and amortization of capital expended at our CO_2 source fields and industrial sources. This per-Mcf CO_2 cost during the second quarter of 2019 was lower than the $0.44 per Mcf comparable measure during the second quarter of 2018 and $0.39 per Mcf comparable measure during the first quarter of 2019 due to a lower utilization of industrial-sourced CO_2 in our Gulf Coast region, which has a higher average cost than our naturally-occurring CO_2 sources.

Transportation and Marketing Expenses

Transportation and marketing expenses primarily consist of amounts incurred relating to the transportation, marketing, and processing of oil and natural gas production. Transportation and marketing expenses were $11.2 million and $10.1 million for the

three months ended June 30, 2019 and 2018, respectively, and $22.0 million and $20.6 million for the six months ended June 30, 2019 and 2018, respectively.

Taxes Other Than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income decreased $1.7 million (6%) during the three months ended June 30, 2019, compared to the same prior-year period and decreased $5.3 million (10%) during the six months ended June 30, 2019, compared to the same period in 2018, due primarily to a decrease in production taxes resulting from lower oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data and employees	2019	2018	2019	2018
Gross cash compensation and administrative costs	$ 53,919	$ 57,484	$ 108,620	$ 114,522
Gross stock-based compensation	4,669	3,227	8,975	6,529
Operator labor and overhead recovery charges	(30,740)	(32,187)	(60,615)	(63,324)
Capitalized exploration and development costs	(10,342)	(9,112)	(20,549)	(18,083)
Net G&A expense	$ 17,506	$ 19,412	$ 36,431	$ 39,644
G&A per BOE				
Net cash administrative costs	$ 2.56	$ 2.99	$ 2.74	$ 3.11
Net stock-based compensation	0.66	0.45	0.64	0.47
Net G&A expenses	$ 3.22	$ 3.44	$ 3.38	$ 3.58
Employees as of June 30	846	880		

Our net G&A expenses on an absolute-dollar basis decreased $1.9 million (10%) and $3.2 million (8%), or $0.22 (6%) and $0.20 (6%) on a per-BOE basis, during the three and six months ended June 30, 2019, respectively, compared to the same periods in 2018, primarily due to our continued focus on cost reduction efforts and reduction in performance-based compensation.

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

In thousands, except per-BOE data and interest rates	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Cash interest[1]	$ 48,371	$ 45,542	$ 96,319	$ 92,145
Less: interest not reflected as expense for financial reporting purposes[1]	(21,355)	(21,614)	(42,634)	(43,663)
Noncash interest expense	1,194	1,131	2,457	2,268
Amortization of debt discount[2]	444	—	444	—
Less: capitalized interest	(8,238)	(8,851)	(18,772)	(17,303)
Interest expense, net	$ 20,416	$ 16,208	$ 37,814	$ 33,447
Interest expense, net per BOE	$ 3.76	$ 2.87	$ 3.51	$ 3.02
Average debt principal outstanding[3]	$ 2,559,822	$ 2,550,450	$ 2,550,278	$ 2,646,049
Average cash interest rate[4]	7.6%	7.1%	7.6%	7.0%

(1) Cash interest includes the portion of interest on certain debt instruments accounted for as a reduction of debt for GAAP financial reporting purposes in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*. The portion of interest treated as a reduction of debt relates to our 2021 Senior Secured Notes, 9¼% Senior Secured Second Lien Notes due 2022 (the "2022 Senior Secured Notes"), and our previously outstanding 3½% Convertible Senior Notes due 2024 and 5% Convertible Senior Notes due 2023. See below for further discussion.
(2) Represents amortization of debt discounts of $0.1 million and $0.3 million related to the 7¾% Senior Secured Notes and 2024 Convertible Senior Notes, respectively, for the three and six months ended June 30, 2019.
(3) Excludes debt discounts related to our 7¾% Senior Secured Notes and 2024 Convertible Senior Notes.
(4) Includes commitment fees but excludes debt issue costs and amortization of discount.

As reflected in the table above, cash interest expense during the three and six months ended June 30, 2019 increased $2.8 million (6%) and $4.2 million (5%), respectively, when compared to the prior-year periods due primarily to an increase in our weighted-average interest rate.

Capitalized interest was relatively unchanged during the three months ended June 30, 2019 and increased $1.5 million (8%) during the six months ended June 30, 2019, compared to the same periods in 2018, primarily due to an increase in the number of projects that qualify for interest capitalization.

Future interest payable related to our 2021 Senior Secured Notes and 2022 Senior Secured Notes is accounted for in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*, whereby most of the future interest was recorded as debt as of the transaction date, which will be reduced as semiannual interest payments are made. Future interest payable recorded as debt totaled $207.7 million as of June 30, 2019. Therefore, interest expense reflected in our Unaudited Condensed Consolidated Statements of Operations will be approximately $86 million lower annually than the actual cash interest payments on our 2021 Senior Secured Notes and 2022 Senior Secured Notes.

As more fully described in Note 4, *Long-Term Debt*, to the Unaudited Condensed Consolidated Financial Statements, the June 2019 debt exchange transactions were accounted for in accordance with FASC 470-50, *Modifications and Extinguishments*, whereby our new 7¾% Senior Secured Notes and new 2024 Convertible Senior Notes were recorded on our balance sheet at discounts to their principal amounts of $29.6 million and $79.9 million, respectively. These debt discounts will be amortized as interest expense over the terms of the notes; therefore, future interest expense reflected in our Unaudited Condensed Consolidated Statements of Operations will be higher than the actual cash interest payments on our new 7¾% Senior Secured Notes and new 2024 Convertible Senior Notes by approximately $8 million in 2019, $16 million in 2020, $19 million in 2021, $21 million in 2022, $25 million in 2023 and $21 million in 2024.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE data	2019	2018	2019	2018
Oil and natural gas properties	$ 40,110	$ 33,358	$ 76,945	$ 65,229
CO_2 properties, pipelines, plants and other property and equipment	18,154	19,586	38,616	40,166
Total DD&A	$ 58,264	$ 52,944	$ 115,561	$ 105,395
DD&A per BOE				
Oil and natural gas properties	$ 7.38	$ 5.91	$ 7.15	$ 5.89
CO_2 properties, pipelines, plants and other property and equipment	3.34	3.47	3.59	3.63
Total DD&A cost per BOE	$ 10.72	$ 9.38	$ 10.74	$ 9.52

The increase in our oil and natural gas properties depletion during the three and six months ended June 30, 2019, when compared to the same periods in 2018, was primarily due to an increase in depletable costs resulting from increases in our capitalized costs and future development costs associated with our reserves base.

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per-BOE amounts and tax rates	2019	2018	2019	2018
Current income tax expense (benefit)	$ 3,354	$ (754)	$ 2,073	$ (1,786)
Deferred income tax expense	62,023	10,185	52,545	25,237
Total income tax expense	$ 65,377	$ 9,431	$ 54,618	$ 23,451
Average income tax expense per BOE	$ 12.03	$ 1.68	$ 5.07	$ 2.12
Effective tax rate	30.8%	23.8%	31.1%	25.1%
Total net deferred tax liability	$ 362,303	$ 231,761		

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax liability or benefit. Our income taxes are based on an estimated statutory rate of approximately 25% in 2019 and 2018. Our effective tax rate for the three and six months ended June 30, 2019 was higher than our estimated statutory rate, primarily due to establishment of a valuation allowance against a portion of our business interest expense deduction that we estimate will be disallowed. The Tax Cuts and Jobs Act ("The Act"), which was enacted on December 22, 2017, revised the rules regarding the deductibility of business interest expense by limiting that deduction to 30% of adjusted taxable income (as defined), with disallowed amounts being carried forward to future taxable years. Based on our evaluation, using information existing as of the balance sheet date, of the near-term ability to utilize the tax benefits associated with our 2019 disallowed business interest expense, we have established a valuation allowance through our annual estimated effective income tax rate for that portion of our business interest expense that is currently expected to exceed the allowed limitation under The Act.

The current income tax benefits for the three and six months ended June 30, 2018, represent amounts estimated to be receivable resulting from alternative minimum tax credits and certain state tax obligations.

As of June 30, 2019, we had estimated amounts available for carry forward of $57.8 million of enhanced oil recovery credits related to our tertiary operations, $21.6 million of research and development credits, and $18.1 million of alternative minimum tax credits. The alternative minimum tax credits are fully refundable by 2021 and are recorded as a receivable on the balance

sheet. The enhanced oil recovery credits and research and development credits do not begin to expire until 2024 and 2031, respectively.

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	2019	2018	2019	2018
Oil and natural gas revenues	$ 60.80	$ 66.57	$ 58.06	$ 64.63
Receipt (payment) on settlements of commodity derivatives	(0.28)	(9.71)	0.62	(7.96)
Lease operating expenses	(21.70)	(21.34)	(22.61)	(21.56)
Production and ad valorem taxes	(4.33)	(4.50)	(4.23)	(4.55)
Transportation and marketing expenses	(2.07)	(1.78)	(2.04)	(1.86)
Production netback	32.42	29.24	29.80	28.70
CO_2 sales, net of operating and exploration expenses	1.36	1.10	1.43	1.20
General and administrative expenses	(3.22)	(3.44)	(3.38)	(3.58)
Interest expense, net	(3.76)	(2.87)	(3.51)	(3.02)
Other	(0.19)	(0.24)	0.17	0.15
Changes in assets and liabilities relating to operations	0.74	3.51	(4.72)	(1.27)
Cash flows from operations	27.35	27.30	19.79	22.18
DD&A	(10.72)	(9.38)	(10.74)	(9.52)
Deferred income taxes	(11.41)	(1.81)	(4.88)	(2.28)
Gain on extinguishment of debt	18.46	—	9.32	—
Noncash fair value gains (losses) on commodity derivatives[(1)]	4.84	(7.34)	(6.07)	(5.14)
Other noncash items	(1.53)	(3.41)	3.82	1.06
Net income	$ 26.99	$ 5.36	$ 11.24	$ 6.30

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

FORWARD-LOOKING INFORMATION

The data and/or statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in the section *Management's Discussion and Analysis of Financial Condition and Results of Operations*, and information regarding the financial position, business strategy, production and reserve growth, possible or assumed future results of operations, and other plans and objectives for the future operations of Denbury, and general economic conditions 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 their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to further reduce our debt levels or extend debt maturities, together with assumptions based on current and projected production levels, oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, availability of capital, borrowing capacity, price and availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, the nature of any future asset purchases or sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including Cedar Creek Anticline ("CCA"), or the availability of capital for CCA pipeline construction, or its ultimate cost or date of completion, timing of CO_2 injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, levels of 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, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions, the likelihood and extent of an economic slowdown, and other variables surrounding operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; accuracy of our cost estimates; availability or terms of credit in the commercial banking or other debt markets; fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements including, without limitation, the Company's most recent Form 10-K.

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, 2019, we had $80.0 million of outstanding borrowings on our senior secured bank credit facility. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in light of credit downgrades in February 2016, we were required to provide a $41.3 million letter of credit to the lessor, which we provided on March 4, 2016. The letter of credit may be drawn upon in the event we fail to make a payment due under the pipeline financing lease agreement or upon other specified defaults set out in the pipeline financing lease agreement (filed as Exhibit 99.1 to the Form 8-K filed with the SEC on June 5, 2008). The fair values of our senior secured second lien notes, convertible senior notes, and senior subordinated notes are based on quoted market prices. The following table presents the principal and fair values of our outstanding debt as of June 30, 2019.

In thousands	2021	2022	2023	2024	Total	Fair Value
Variable rate debt:						
Senior Secured Bank Credit Facility (weighted average interest rate of 5.1% at June 30, 2019)	$ 80,000	$ —	$ —	$ —	$ 80,000	$ 80,000
Fixed rate debt:						
9% Senior Secured Second Lien Notes due 2021	614,919	—	—	—	614,919	605,695
9¼% Senior Secured Second Lien Notes due 2022	—	455,668	—	—	455,668	428,328
7¾% Senior Secured Second Lien Notes due 2024	—	—	—	528,026	528,026	438,262
7½% Senior Secured Second Lien Notes due 2024	—	—	—	24,638	24,638	19,464
6⅜% Convertible Senior Notes due 2024	—	—	—	245,548	245,548	161,273
6⅜% Senior Subordinated Notes due 2021	51,304	—	—	—	51,304	41,685
5½% Senior Subordinated Notes due 2022	—	94,784	—	—	94,784	54,501
4⅝% Senior Subordinated Notes due 2023	—	—	211,695	—	211,695	106,377

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

Commodity Derivative Contracts

We enter into oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices. In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production through 2020 using both NYMEX and LLS fixed-price swaps and three-way collars. Depending on market conditions, we may continue to add to our existing 2019 and 2020 hedges. See also Note 5, *Commodity Derivative Contracts*, and Note 6*, Fair Value Measurements,* to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

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

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

At June 30, 2019, our commodity derivative contracts were recorded at their fair value, which was a net asset of $32.0 million, a $26.3 million increase from the $5.7 million net asset recorded at March 31, 2019, and a $65.3 million decrease from the $97.3 million net asset recorded at December 31, 2018. These changes are primarily related to the expiration of commodity derivative contracts during the three and six months ended June 30, 2019, new commodity derivative contracts entered into during 2019 for future periods, and to the changes in oil futures prices between December 31, 2018 and June 30, 2019.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of June 30, 2019, and assuming both a 10% increase and decrease thereon, we would expect to receive or make payments on our crude oil derivative contracts as shown in the following table:

	Receipt / (Payment)
In thousands	Crude Oil Derivative Contracts
Based on:	
Futures prices as of June 30, 2019	$ 31,057
10% increase in prices	(14,698)
10% decrease in prices	109,514

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

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, 2019, 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 2019, 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.

Denbury Resources Inc.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our business or finances, litigation is subject to inherent uncertainties. We accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC ("APMTG"). The helium supply contract provides for the delivery of a minimum contracted quantity of helium, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are specified in the contract at up to $8.0 million per contract year and are capped at an aggregate of $46.0 million over the term of the contract.

As the gas processing facility has been shut-in since mid-2014 due to significant technical issues, we have not been able to supply helium under the helium supply contract. In a case filed in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, APMTG claimed multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company claimed that its contractual obligations were excused by virtue of events that fall within the force majeure provisions in the helium supply contract.

On March 11, 2019, the trial court entered a final judgment that a force majeure condition did exist, but the Company's performance was excused by the force majeure provisions of the contract for only a 35-day period in 2014, and as a result the Company should pay APMTG liquidated damages and interest thereon for those time periods from contract commencement to the close of evidence (November 29, 2017) when the Company's performance was not excused as provided in the contract. The Company has filed a notice of appeal of the trial court's ruling to the Wyoming Supreme Court, the results of which cannot be predicted at this time.

The Company's position continues to be that its contractual obligations have been and continue to be excused by events that fall within the force majeure provisions in the helium supply contract. The Company intends to continue to vigorously defend its position and pursue all of its rights.

Absent reversal of the trial court's ruling on appeal, the Company anticipates total liquidated damages would equal the $46.0 million aggregate cap under the helium supply contract (including $14.2 million of liquidated damages for the contract years ending July 31, 2018 and July 31, 2019) plus $4.2 million of associated costs (through June 30, 2019), for a total of $50.2 million, included in "Other liabilities" in our Unaudited Condensed Consolidated Balance Sheets as of June 30, 2019.

Environmental Protection Agency Matter Concerning Certain Fields

The Company previously entered into a series of tolling agreements with the Environmental Protection Agency ("EPA"), and has been in discussions with the agency over the past several years regarding the EPA's contention that it has causes of action under the Clean Water Act ("CWA") related to releases (principally between 2008 and 2013) of oil and produced water containing small amounts of oil in the Citronelle Field in southern Alabama and several fields in Mississippi. The EPA has taken the position that these releases were in violation of the CWA.

In April 2019, the discussions concluded and the parties reached agreement on a proposed Consent Decree among the Company, the United States, and the State of Mississippi resolving the allegations of CWA violations. The proposed Consent Decree was lodged in U.S. District Court in Mississippi for a 30-day public comment period and will become effective upon the District Court entering the Consent Decree as a judgment of the court. Once effective, the Consent Decree will require the Company to pay civil penalties totaling $3.5 million in the aggregate to the United States and the State of Mississippi, to implement enhancements to the Company's mechanical integrity program designed to minimize the occurrence and impact of any future releases at the Mississippi fields, and to perform other relief such as enhanced training and reporting requirements with respect to the Mississippi fields.

Item 1A. Risk Factors

Please refer to Item 1A of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018. There have been no material changes to our risk factors contained in our Annual Report on Form 10-K for the fiscal year ended December 31, 2018 other than as detailed below.

If we cannot meet the "price criteria" for continued listing on the NYSE, the NYSE may delist our common stock, which could have an adverse impact on the trading volume, liquidity and market price of our common stock, or the trading prices of our 6⅜% Convertible Senior Notes due 2024.

If we do not maintain an average closing price of $1.00 or more for our common stock over any consecutive 30 trading-day period, the NYSE may delist our common stock for a failure to maintain compliance with the NYSE price criteria listing standards. As of August 8, 2019, the average closing price of our common stock over the immediately preceding 30 consecutive trading-day period was $1.14, although on August 8, 2019 the closing price of our common stock on the NYSE was $1.08 per share. Despite NYSE rules and processes that provide a period of time to cure non-compliance with this NYSE standard (during which time the issuer's common stock generally continues to be traded on the NYSE), there is no assurance that trading prices of our common stock or other steps we take would be successful in assuring our long-term listing on the NYSE. A delisting of our common stock from the NYSE would likely reduce the liquidity and market price of our common stock, (along with the trading prices of our 6⅜ % Convertible Senior Notes due 2024), reduce the number of investors willing to hold or acquire our common stock, and negatively impact our ability to raise equity financing.

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 2019:

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 2019	782	$ 2.29	—	$ 210.1
May 2019	533	1.60	—	210.1
June 2019	346	1.24	—	210.1
Total	1,661		—	

(1) Shares purchased during the second quarter of 2019 were made in connection with the surrender of shares by our employees to satisfy their tax withholding requirements related to the vesting of restricted and performance shares.

(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 in the near future. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Denbury Resources Inc.

Item 6. Exhibits

Exhibit No.	Exhibit
3	Certificate of Amendment and Second Restated Certificate of Incorporation of Denbury Resources Inc., filed with the Delaware Secretary of State on May 22, 2019 (incorporated by reference to Exhibit 3.1 of Form 8-K filed by the Company on May 28, 2019).
4(a)	Indenture, dated as of June 19, 2019, among the Company, the Subsidiary Guarantors named therein, and Wilmington Trust, National Association, as Trustee and Collateral Trustee, with respect to $528,026,000 aggregate principal amount of 7¾% Senior Secured Second Lien Notes due 2024 (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on June 24, 2019).
4(b)	Form of Global Note representing the 7¾% Senior Secured Second Lien Notes due 2024 (incorporated by reference to Exhibit 4.2 of Form 8-K filed by the Company on June 24, 2019).
4(c)	Indenture, dated as of June 19, 2019, among the Company, the Subsidiary Guarantors named therein, and Wilmington Trust, National Association, as Trustee, with respect to $245,548,000 aggregate principal amount of 6⅜% Convertible Senior Notes due 2024 (incorporated by reference to Exhibit 4.3 of Form 8-K filed by the Company on June 24, 2019).
4(d)	Form of Global Note representing the 6⅜% Convertible Senior Notes due 2024 (incorporated by reference to Exhibit 4.4 of Form 8-K filed by the Company on June 24, 2019).
10(a)	Collateral Trust Joinder, dated as of June 19, 2019, by and between Wilmington Trust, National Association, as Trustee, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on June 24, 2019).
10(b)	Priority Confirmation Joinder, dated as of June 19, 2019, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 on Form 8-K filed by the Company on June 24, 2019).
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 - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document

* Included herewith.

Denbury Resources Inc.

SIGNATURES

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

	DENBURY RESOURCES INC.
August 9, 2019	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer
August 9, 2019	/s/ Alan Rhoades
	Alan Rhoades Vice President and Chief Accounting Officer