GOODRICH PETROLEUM CORP
Form 10-Q
August 07, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-Q
QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended June 30, 2018
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 001-12719
GOODRICH PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	76-0466193
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

801 Louisiana, Suite 700
Houston, Texas 77002
(Address of principal executive offices) (Zip Code)
(Registrant's telephone number, including area code): (713) 780-9494

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) 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, 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.

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
(Do not check if a smaller reporting company)	Emerging growth 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
Indicate by check mark whether the Registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed

by a court. Yes No

The Registrant had 11,838,386 shares of common stock outstanding on August 6, 2018.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
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PART I – FINANCIAL INFORMATION
Item 1—Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)
(Unaudited)

	June 30, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,729	$25,992
Accounts receivable, trade and other, net of allowance	1,969	1,371
Accrued oil and natural gas revenue	7,317	4,958
Fair value of oil and natural gas derivatives	673	2,034
Inventory	1,722	2,521
Prepaid expenses and other	950	1,614
Total current assets	14,360	38,490
PROPERTY AND EQUIPMENT:		
Unevaluated properties	5,878	5,984
Oil and natural gas properties (full cost method)	145,074	120,333
Furniture, fixtures and equipment	1,291	1,039
	152,243	127,356
Less: Accumulated depletion, depreciation and amortization	(24,783)	(15,899)
Net property and equipment	127,460	111,457
Fair value of oil and natural gas derivatives	447	566
Deferred tax asset	937	937
Other	626	691
TOTAL ASSETS	$143,830	$152,141
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$21,140	$17,204
Accrued liabilities	13,381	18,075
Fair value of oil and natural gas derivatives	2,045	1,002
Total current liabilities	36,566	36,281
Long term debt, net	50,080	55,725
Accrued abandonment cost	3,442	3,367
Fair value of oil and natural gas derivatives	608	517
Total liabilities	90,696	95,890
Commitments and contingencies (See Note 9)		
STOCKHOLDERS' EQUITY:		
Preferred stock: 10,000,000 shares $1.00 par value authorized, and none issued and outstanding	—	—
Common stock: $0.01 par value, 75,000,000 shares authorized, and 11,836,986 shares issued and outstanding at June 30, 2018 and $0.01 par value, 75,000,000 shares authorized, and 10,770,962 shares issued and outstanding at December 31, 2017	119	108
Treasury stock (75,475 and zero shares, respectively)	(832)	—
Additional paid in capital	74,135	68,446
Accumulated deficit	(20,288)	(12,303)
Total stockholders' equity	53,134	56,251

TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$143,830	$152,141

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)
(Unaudited)

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
REVENUES:				
Oil and natural gas revenues	$17,784	$12,115	$29,627	$21,526
Other	51	350	42	352
	17,835	12,465	29,669	21,878
OPERATING EXPENSES:				
Lease operating expense	2,465	2,950	5,031	7,261
Production and other taxes	669	424	1,309	1,083
Transportation and processing	2,086	1,868	3,398	3,044
Depreciation, depletion and amortization	5,560	3,083	9,012	5,377
General and administrative	4,803	3,772	9,999	8,235
Other	165	—	165	—
	15,748	12,097	28,914	25,000
Operating income (loss)	2,087	368	755	(3,122)
OTHER INCOME (EXPENSE):				
Interest expense	(2,732)	(2,360)	(5,405)	(4,539)
Interest income and other expense	116	12	109	21
Gain (loss) on commodity derivatives not designated as hedges	(2,174)	766	(3,155)	506
	(4,790)	(1,582)	(8,451)	(4,012)
Reorganization items, net	42	—	(289)	195
Loss before income taxes	(2,661)	(1,214)	(7,985)	(6,939)
Income tax expense	—	—	—	—
Net loss	$(2,661)	$(1,214)	$(7,985)	$(6,939)
PER COMMON SHARE				
Net loss applicable to common stock - basic	$(0.23)	$(0.13)	$(0.70)	$(0.74)
Net loss applicable to common stock - diluted	$(0.23)	$(0.13)	$(0.70)	$(0.74)
Weighted average common shares outstanding - basic	11,629	9,670	11,424	9,381
Weighted average common shares outstanding - diluted	11,629	9,670	11,424	9,381

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(7,985)	$(6,939)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	9,012	5,377
(Gain) loss on commodity derivatives not designated as hedges	3,155	(506)
Net cash received from (paid for) settlement of commodity derivative instruments	(541)	147
Share based compensation (non-cash)	3,167	3,379
Amortization of finance cost, debt discount, paid in-kind interest and accretion	5,157	3,975
(Gain) loss from material transfers and inventory write-down	218	(73)
Reorganization items, net	289	(78)
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	(598)	1,757
Accrued oil and natural gas revenue	(2,359)	(2,626)
Prepaid expenses and other	(20)	(400)
Accounts payable	3,936	11,211
Accrued liabilities	(776)	904
Net cash provided by operating activities	12,655	16,128
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(53,100)	(17,519)
Proceeds from sale of assets	26,920	—
Net cash used in investing activities	(26,180)	(17,519)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Principal payments of bank borrowings	(16,723)	—
Proceeds from bank borrowings	6,000	—
Net receipts (payments) related to Convertible Second Lien Notes	3	(170)
Issuance cost, net	(10)	(278)
Other	(8)	—
Net cash used in financing activities	(10,738)	(448)
DECREASE IN CASH AND CASH EQUIVALENTS	(24,263)	(1,839)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	25,992	36,850
CASH AND CASH EQUIVALENTS, END OF PERIOD	$1,729	$35,011
Supplemental disclosures of cash flow information:		
Cash paid for reorganization items, net	$543	$828
Cash paid for interest	$249	$581
Increase (decrease) in non-cash capital expenditures	$(2,805)	$1,526

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—Description of Business and Significant Accounting Policies

Goodrich Petroleum Corporation ("Goodrich" and, together with its wholly-owned subsidiary, Goodrich Petroleum Company, L.L.C. (the "Subsidiary"), "we," "our," or the "Company") is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in (i) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend, (ii) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale Trend ("TMS"), and (iii) South Texas, which includes the Eagle Ford Shale Trend.

Basis of Presentation

The consolidated financial statements of the Company included in this Quarterly Report on Form 10-Q have been prepared, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC") and accordingly, certain information normally included in financial statements prepared in accordance with United States Generally Accepted Accounting Principles ("US GAAP") has been condensed or omitted. This information should be read in conjunction with our consolidated financial statements and notes contained in our annual report on Form 10-K for the year ended December 31, 2017. Operating results for the three and six months ended June 30, 2018 are not necessarily indicative of the results that may be expected for the full year or for any interim period.

Principles of Consolidation—The consolidated financial statements include the financial statements of the Company and the Subsidiary. Intercompany balances and transactions have been eliminated in consolidation. The consolidated financial statements reflect all normal recurring adjustments that, in the opinion of management, are necessary for a fair presentation. Certain data in prior periods' financial statements have been adjusted to conform to the presentation of the current period. We have evaluated subsequent events through the date of this filing.

Use of Estimates— Our management has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with US GAAP.

Cash and Cash Equivalents—Cash and cash equivalents includes cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at the date of purchase.

Accounts Payable—Accounts payable consisted of the following amounts as of June 30, 2018 and December 31, 2017:

(In thousands)	June 30, 2018	December 31, 2017
Trade payables	$8,300	$ 4,092
Revenue payable	12,234	10,692
Prepayments from partners	374	2,193
Miscellaneous payables	232	227
Total Accounts payable	$21,140	$ 17,204

Accrued Liabilities—Accrued liabilities consisted of the following amounts as of June 30, 2018 and December 31, 2017:

(In thousands)	June 30, 2018	December 31, 2017
Accrued capital expenditures	$7,706	$ 10,511
Accrued lease operating expense	843	786

Accrued production and other taxes	713	449
Accrued transportation and gathering	1,132	1,130
Accrued performance bonus	1,854	3,869
Accrued interest	3	244
Accrued office lease	658	696
Accrued reorganization costs	307	168
Accrued general and administrative expense and other	165	222
Total Accrued liabilities	$13,381	$ 18,075

Inventory –Inventory consists of casing and tubulars that are expected to be used in our capital drilling program. Inventory is carried on the Consolidated Balance Sheets at the lower of cost or market.

Property and Equipment—Under US GAAP, two acceptable methods of accounting for oil and natural gas properties are allowed. These are the Successful Efforts Method and the Full Cost Method. Entities engaged in the production of oil and natural gas have the option of selecting either method for application in the accounting for their properties. The principal differences between the two methods are in the treatment of exploration costs, the computation of Depreciation, Depletion and Amortization ("DD&A") expense and the assessment of impairment of oil and natural gas properties. We use the Full Cost Method to account for our investment in oil and gas properties.

Under the Full Cost Method, we capitalize all costs associated with acquisitions, exploration, development and estimated abandonment costs. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, but do not include any costs related to production, general corporate overhead or similar activities. Unevaluated property costs are excluded from the amortization base until we make a determination as to the existence of proved reserves on the respective property or impairment. We review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to proved oil and natural gas properties and thereby subject to DD&A and the full cost ceiling test. For the three months ended June 30, 2018 and 2017, we transferred $0.3 million and $1.9 million, respectively, from unevaluated properties to proved oil and natural gas properties. For the six months ended June 30, 2018 and 2017, we transferred $0.4 million and $12.8 million, respectively, from unevaluated properties to proved oil and natural gas properties. Our sales of oil and natural gas properties are accounted for as adjustments to net proved oil and natural gas properties with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

We amortize our investment in oil and natural gas properties through DD&A expense using the units of production (the "UOP") method. An amortization rate is calculated based on total proved reserves converted to equivalent thousand cubic feet of natural gas ("Mcfe") as the denominator and the net book value of evaluated oil and gas asset together with the estimated future development cost of the proved undeveloped reserves as the numerator. The rate calculated per Mcfe is applied against the periods' production also converted to Mcfe to arrive at the periods' DD&A expense.

Depreciation of furniture, fixtures and equipment, consisting of office furniture, computer hardware and software and leasehold improvements, is computed using the straight-line method over their estimated useful lives, which vary from three to five years.

Full Cost Ceiling Test—The Full Cost Method requires that at the conclusion of each financial reporting period, the present value of estimated future net cash flows from proved reserves (adjusted for hedges and excluding cash flows related to estimated abandonment costs), be compared to the net capitalized costs of proved oil and natural gas properties, net of related deferred taxes. This comparison is referred to as a "ceiling test". If the net capitalized costs of proved oil and natural gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and natural gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are calculated based on a 12-month average pricing assumption.

There were no Full Cost Ceiling Test write-downs for the three or six months ended June 30, 2018 or 2017.

Fair Value Measurement—Fair value is defined 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. The fair value of an asset should reflect its highest and best use by market participants, whether in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of non-performance, which includes, among other things, our credit risk.

We use various methods, including the income approach and market approach, to determine the fair values of our financial instruments that are measured at fair value on a recurring basis, which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments into three Levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between Levels.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

Each of these Levels and our corresponding instruments classified by Level are further described below:

- Level 1 Inputs— unadjusted quoted market prices in active markets for identical assets or liabilities. We have no Level 1 instruments;
- Level 2 Inputs— quotes that are derived principally from or corroborated by observable market data. Included in this Level are our 2017 Senior Credit Facility and commodity derivatives whose fair values are based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties; and
- Level 3 Inputs— unobservable inputs for the asset or liability, such as discounted cash flow models or valuations, based on our various assumptions and future commodity prices. Included in this Level would be our initial measurement of asset retirement obligations.

As of June 30, 2018 and December 31, 2017, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

Asset Retirement Obligations—Asset retirement obligations are related to the abandonment and site restoration requirements that result from the exploration and development of our oil and natural gas properties. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Accretion expense is included in “Depreciation, depletion and amortization” on our Consolidated Statements of Operations. See Note 3.

The estimated fair value of the Company’s asset retirement obligations at inception is determined by utilizing the income approach by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligations was classified as Level 3 in the fair value hierarchy.

Revenue Recognition—Oil and natural gas revenues are recognized upon delivery of our produced oil and natural gas volumes to our customers. Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized in accordance with when the producing company records revenue on those volumes. We record a liability or an asset for natural gas balancing when we have sold more or less than our working interest share of natural gas production, respectively. At June 30, 2018 and December 31, 2017, the net liability for natural gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted. See Note 2.

Derivative Instruments—We use derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. Accounting standards related to derivative instruments and hedging activities require that all derivative instruments subject to the requirements of those standards be measured at fair value and recognized as assets or liabilities in the balance sheet. We offset the fair value of our asset and liability positions with the same counterparty for each commodity type. Changes in fair value are required to be recognized in earnings unless specific hedge accounting criteria are met. All of our realized gain or losses on our derivative contracts are the result of cash settlements. We have not designated any of our derivative contracts as hedges; accordingly, changes in fair value are reflected in earnings. See Note 8.

Income Taxes—We account for income taxes, as required, under the liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize, as required, the financial statement benefit of an uncertain tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. See Note 7.

Net Income or Net Loss Per Share—Basic income (loss) per common share is computed by dividing net income (loss) applicable to common stockholders for each reporting period by the weighted-average number of common shares outstanding during the period. Diluted income (loss) per common share is computed by dividing net income (loss) applicable to common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive restricted stock calculated using the treasury stock method and the potential dilutive effect of the conversion of convertible securities, such as warrants and convertible notes, into shares of our common stock. See Note 6.

Commitments and Contingencies—Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties, and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries from third parties, when probable of realization, are separately recorded and are not offset against the related environmental liability. See Note 9.

Share-Based Compensation—We account for our share-based transactions using the fair value as of the grant date and recognize compensation expense over the requisite service period.

Guarantee—As of June 30, 2018, Goodrich Petroleum Company LLC, the wholly owned subsidiary of Goodrich Petroleum Corporation, was the Subsidiary Guarantor of our 13.50% Convertible Second Lien Senior Secured notes due 2019 (the “Convertible Second Lien Notes”).

Debt Issuance Cost—The Company records debt issuance costs associated with its Convertible Second Lien Notes as a contra balance to long term debt, net in our Consolidated Balance Sheets, which is amortized straight-line over the life of the Convertible Second Lien Notes. Debt issuance costs associated with our revolving credit facility debt are recorded in other assets in our Consolidated Balance Sheets, which is amortized straight-line over the life of such debt.

New Accounting Pronouncements

On June 20, 2018, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2018-07, Compensation—Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting. The amendments in this ASU expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees. The amendments specify that Topic 718 applies to all share-based payment transactions in which a grantor acquires goods or services to be used or consumed in a grantor’s own operations by issuing share-based payment awards. The amendments also clarify that Topic 718 does not apply to share-based payments used to effectively provide (1) financing to the issuer or (2) awards granted in conjunction with selling goods or services to customers as part of a contract accounted for under Topic 606, Revenue from Contracts with Customers. For public entities, the amendments in this ASU are effective for annual periods beginning after December 15, 2018. We have not granted or issued share-based payments to nonemployees. We have evaluated the provisions of this ASU and do not expect it to have a material impact on our consolidated financial statements.

On March 13, 2018, the FASB issued ASU 2018-05, Income Taxes (Topic 740). The ASU adds seven paragraphs to the Accounting Standards Codification “ASC” 740, Income Taxes, that contain SEC guidance related to Staff Accounting Bulletin 118 (“Income Tax Accounting Implications of the Tax Cuts and Jobs Act”) as a result of the tax legislation passed in 2017 known as the “Tax Cuts and Jobs Act”. Specifically, the staff intended to address situations where the accounting under ASC Topic 740 is incomplete for certain income tax effects of the Tax Cuts and Jobs Act upon issuance of an entity’s financial statements for the reporting period in which the Tax Cuts and Jobs Act was enacted. The Company notes that it has considered the updates to ASC 740 as a result of the Tax Cuts and Jobs Act and has prepared its consolidated financial statements in accordance with the Tax Cuts and Jobs Act. See Note 7 for further discussion.

On August 28, 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities. This ASU is intended to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. In addition, the amendments in this ASU make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP based on the feedback received from preparers, auditors, users, and other stakeholders. For public entities, the amendments in this ASU are effective for annual periods beginning after December 15, 2018. We do not expect this ASU to have a material impact on our consolidated financial statements as we currently mark-to-market all of our derivative positions; however, we are evaluating the impact of this ASU should we choose to utilize hedge accounting in the future.

On February 25, 2016, the FASB issued ASU 2016-02, Leases (Topic 842) and subsequently issued ASU 2018-10, Codification Improvements to Topic 842, Leases in July 2018. The key difference between the existing standards and ASU 2016-02 is the requirement for lessees to recognize on their balance sheet all lease contracts with lease terms greater than 12 months, including operating leases. Specifically, lessees are required to recognize on the balance sheet at lease commencement, both (i) a right-of-use asset, representing the lessee's right to use the leased asset over the term of the lease, and (ii) a lease liability, representing the lessee's contractual obligation to make lease payments over the term of the lease. For lessees, ASU 2016-02 requires classification of leases as either operating or finance leases, which are similar to the current operating and capital lease classifications. However, the distinction between these two classifications under the ASU does not relate to balance sheet treatment, but relate to treatment and recognition in the statements of income and cash flows. Lessor accounting is largely unchanged from current US GAAP. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, for public entities. Early application is permitted. The Company has developed a project plan to guide the implementation of ASU 2016-02, which includes assessing our portfolio of leases and determining a process for ensuring completeness of our repository of active leases. We have not yet completed our evaluation of the impact the new lease accounting guidance will have on our consolidated financial statements; however, we do expect to recognize right of use assets and lease liabilities for our operating leases with terms longer than 12 months in the consolidated balance sheet upon adoption.

NOTE 2—Revenue Recognition

On January 1, 2018, we adopted ASU 2014-09, Revenue from Contracts with Customers, and the series of related ASU's that followed under ASC Topic 606 (collectively, "Topic 606"). Under Topic 606, revenue will generally be recognized upon delivery of our produced oil and natural gas volumes to our customers. Our customer sales contracts include oil and natural gas sales. Under Topic 606, each unit (Mcf or barrel) of commodity product represents a separate performance obligation which is sold at variable prices, determinable on a monthly basis. The pricing provisions of our contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, product quality and prevailing supply and demand conditions in the geographic areas in which we operate. We will allocate the transaction price to each performance obligation and recognize revenue upon delivery of the commodity product when the customer obtains control. Control of our produced natural gas volumes passes to our customers at specific metered points indicated in our natural gas contracts. Similarly, control of our produced oil volumes passes to our customers when the oil is measured either by a trucking oil ticket or by a meter when entering an oil pipeline. The Company has no control over the commodities after those points and the measurement at those points dictates the amount on which the customer's payment is based. Our oil and natural gas revenue streams include volumes burdened by royalty and other joint owner working interests. Our revenues are recorded and presented on our financial statements net of the royalty and other joint owner working interests. Our revenue stream does not include any payments for services or ancillary items other than sale of oil and natural gas.

We record revenue in the month our production is delivered to the purchaser. However, settlement statements and payments for our oil and natural gas sales may not be received for up to 60 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized. As of June 30, 2018 and December 31, 2017, receivables from contracts with customers were $7.3 million and $5.0 million, respectively.

Topic 606 will not change our pattern of timing of revenue recognition. We utilized the full retrospective method for adoption of Topic 606, and in accordance with this method our consolidated financial statements for periods prior to January 1, 2018 were not materially affected or revised. We also do not anticipate a material impact on our financial statements on an ongoing basis.

The following tables present our oil and natural gas revenues disaggregated by revenue source and by operated and non-operated properties:

	Three Months Ended June 30, 2018				Six Months Ended June 30, 2018			
(In thousands)	Oil Revenue	Gas Revenue	NGL Revenue	Total Revenue (As Reported)	Oil Revenue	Gas Revenue	NGL Revenue	Total Revenue (As Reported)
Operated	$3,835	$ 10,900	$ —	$ 14,735	$7,634	$ 16,701	$ —	$ 24,335
Non-operated	133	2,912	4	3,049	276	5,008	8	5,292
Total oil and natural gas revenues	$3,968	$ 13,812	$ 4	$ 17,784	$7,910	$ 21,709	$ 8	$ 29,627

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

(In thousands)	Three Months Ended June 30, 2017				Six Months Ended June 30, 2017			
	Oil Revenue	Gas Revenue	NGL Revenue	Total Revenue (As Reported)	Oil Revenue	Gas Revenue	NGL Revenue	Total Revenue (As Reported)
Operated	$3,888	$4,716	$ —	$8,604	$7,867	$6,062	$ —	$13,929
Non-operated	141	3,366	4	3,511	272	7,315	10	7,597
Total oil and natural gas revenues	$4,029	$8,082	$ 4	$12,115	$8,139	$13,377	$ 10	$21,526

NOTE 3—Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the six months ended June 30, 2018 is as follows (in thousands):

	Six Months Ended June 30, 2018
Beginning balance at December 31, 2017	$ 3,367
Liabilities incurred	122
Accretion expense	128
Dispositions *	(175)
Ending balance at June 30, 2018	$ 3,442
Current liability	$ —
Long term liability	$ 3,442

* - See Note 10 for further information on the dispositions during the three and six months ended June 30, 2018.

NOTE 4—Debt

Debt consisted of the following balances as of the dates indicated (in thousands):

	June 30, 2018		December 31, 2017	
	Principal	Carrying Amount	Principal	Carrying Amount
2017 Senior Credit Facility	$6,000	$6,000	$16,723	$16,723
Convertible Second Lien Notes (1)	50,224	44,080	47,015	39,002
Total debt	$56,224	$50,080	$63,738	$55,725

(1) The debt discount is being amortized using the effective interest rate method based upon a maturity date of August 30, 2019. The principal includes $10.2 million and $7.0 million of paid in-kind interest at June 30, 2018 and December 31, 2017, respectively. The carrying value includes $6.1 million and $8.0 million of unamortized debt discount at June 30, 2018 and December 31, 2017, respectively.

The following table summarizes the total interest expense for the periods shown including contractual interest expense, amortization of debt discount, accretion and financing costs and the effective interest rate on the liability component of the debt (amounts in thousands, except effective interest rates):

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017			Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	Interest Expense	Effective Interest Rate		Interest Expense	Effective Interest Rate		Interest Expense	Effective Interest Rate		Interest Expense	Effective Interest Rate	
2017 Senior Credit Facility	$75	*		$—	—	%	$248	7.8	%	$—	—	%
Exit Credit Facility	—	—	%	279	6.6	%	—	—	%	531	6.3	%
Convertible Second Lien Notes (1)	2,657	24.7	%	2,081	24.3	%	5,157	24.8	%	4,008	24.3	%
Total interest expense	$2,732			$2,360			$5,405			$4,539		

* - Not meaningful due to the timing of borrowings during the three months ended June 30, 2018.

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(1) Interest expense for the three months ended June 30, 2018 included $1.0 million of debt discount amortization and $1.6 million of paid in-kind interest, and interest expense for the three months ended June 30, 2017 included $0.7 million of debt discount amortization and $1.4 million of paid in-kind interest. Interest expense for the six months ended June 30, 2018 included $1.8 million of debt discount amortization and $3.2 million of paid in-kind interest, and interest expense for the six months ended June 30, 2017 included $1.2 million of debt discount amortization and $2.8 million of paid in-kind interest.

Exit Credit Facility

On October 12, 2016, upon consummation of the plan of reorganization and emergence from bankruptcy, the Company entered into an Exit Credit Agreement (the “Exit Credit Agreement”) with the Subsidiary, as borrower (the “Borrower”), and Wells Fargo Bank, National Association, as administrative agent, and certain other lenders party thereto. Pursuant to the Exit Credit Agreement, the lenders party thereto agreed to provide the Borrower with a $20.0 million senior secured term loan credit facility (the “Exit Credit Facility”). On October 17, 2017, the Exit Credit Facility was paid off in full and replaced with the 2017 Senior Credit Facility described below.

2017 Senior Credit Facility

On October 17, 2017, the Company entered into the Amended and Restated Senior Secured Revolving Credit Agreement (the “Credit Agreement”) with the Subsidiary, as borrower, JP Morgan Chase Bank, N.A. as administrative agent, and certain lenders that are party thereto, which provides for revolving loans of up to the borrowing base then in effect (the “2017 Senior Credit Facility”). The 2017 Senior Credit Facility amends, restates and refinances the obligations under the Exit Credit Facility. The 2017 Senior Credit Facility matures (a) October 17, 2021 or (b) if the Convertible Second Lien Notes (as defined below) have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by September 30, 2019, September 30, 2019. The maximum credit amount under the 2017 Senior Credit Facility at June 30, 2018 was $250.0 million with a borrowing base of $40.0 million. The borrowing base is scheduled to be redetermined in March and September of each calendar year, and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, each of the Borrower and the administrative agent may request one unscheduled redetermination of the borrowing base between scheduled redeterminations. The amount of the borrowing base is determined by the lenders in their sole discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. On July 13, 2018, the borrowing base was increased to $60.0 million with an elected draw limit of $50.0 million in recognition of the limitation set forth in the Convertible Second Lien Notes. The Company may also request the issuance of letters of credit under the Credit Agreement in an aggregate amount up to $10.0 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

All amounts outstanding under the 2017 Senior Credit Facility bear interest at a rate per annum equal to, at the Company's option, either (i) the alternative base rate plus an applicable margin ranging from 1.75% to 2.75%, depending on the percentage of the borrowing base that is utilized, or (ii) adjusted LIBOR plus an applicable margin from 2.75% to 3.75%, depending on the percentage of the borrowing base that is utilized. Undrawn amounts under the 2017 Senior Credit Facility are subject to a 0.50% commitment fee. To the extent that a payment default exists and is continuing, all amounts outstanding under the 2017 Senior Credit Facility will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto. As of June 30, 2018, the interest rate on the 2017 Senior Credit Facility was 6.75%.

The 2017 Senior Credit Facility also contains certain financial covenants, including (i) the maintenance of a ratio of Total Debt (as defined in the Credit Agreement) to EBITDAX not to exceed 4.00 to 1.00 as of the last day of any fiscal quarter, (ii) a current ratio (based on the ratio of current assets to current liabilities) not to be less than 1.00 to

1.00 and (iii) until no Convertible Second Lien Notes remain outstanding, (A) the maintenance of a ratio of Total Proved PV10% attributable to the Company's and Borrower's Proved Reserves (as defined in the Credit Agreement) to Total Secured Debt (net of any Unrestricted Cash not to exceed $10.0 million) not to be less than 1.50 to 1.00 and (B) minimum liquidity requirements.

The obligations under the Credit Agreement are guaranteed by the Company and are secured by a first lien security interest in substantially all of the assets of the Company and the Subsidiary.

As of June 30, 2018, the Company had $6.0 million outstanding borrowings. The Company also had $0.5 million of unamortized debt issuance costs recorded as of June 30, 2018 related to the 2017 Senior Credit Facility.

As of June 30, 2018, the Company was in compliance with all covenants within the 2017 Senior Credit Facility.

13.50% Convertible Second Lien Senior Secured Notes Due 2019

On October 12, 2016, upon emergence from bankruptcy, the Company and the Subsidiary, entered into a purchase agreement (the "Purchase Agreement") with each entity identified as a Shenkman Purchaser on Appendix A to the Purchase Agreement (collectively, the "Shenkman Purchasers"), CVC Capital Partners (acting through such of its affiliates to managed funds as it deems appropriate), J.P. Morgan Securities LLC (acting through such of its affiliates or managed funds as it deems appropriate), Franklin Advisers, Inc. (as investment manager on behalf of certain funds and accounts), O'Connor Global Multi-Strategy Alpha Master Limited and Nineteen 77 Global Multi-Strategy Alpha (Levered) Master Limited (collectively, and together with each of their successors and assigns, the "Purchasers"), in connection with the issuance of $40.0 million aggregate principal amount of the Company's 13.50% Convertible Second Lien Senior Secured Notes due 2019 (the "Convertible Second Lien Notes").

The aggregate principal amount of the Convertible Second Lien Notes is convertible at the option of the Purchasers at any time prior to the scheduled maturity date at $21.33 per share, subject to adjustments. At closing, the Purchasers were issued 10-year costless warrants to acquire 2.5 million shares of common stock. Holders of the Convertible Second Lien Notes have a second priority lien on all assets of the Company, and have a continuing right to appoint two members to our Board of Directors (the "Board") as long as the Convertible Second Lien Notes are outstanding.

The Convertible Second Lien Notes as set forth in the agreement, will mature on August 30, 2019 or six months after the maturity of our current revolving credit facility but in no event later than March 30, 2020. The 2017 Senior Credit Facility matures no earlier than September 30, 2019; consequently, the Convertible Second Lien Notes will mature on March 30, 2020. The Convertible Second Lien Notes bear interest at the rate of 13.50% per annum, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year. The Company may elect to pay all or any portion of interest in-kind on the then outstanding principal amount of the Convertible Second Lien Notes by increasing the principal amount of the outstanding Convertible Second Lien Notes or by issuing additional Second Lien Notes ("PIK Interest Notes"). The PIK Interest Notes are not convertible. During such time as the Exit Credit Agreement (but not any refinancing or replacement thereof) was in effect, interest on the Convertible Second Lien Notes had to be paid in-kind. As to the new 2017 Senior Credit Facility, interest on the Convertible Second Lien Notes must be paid in-kind; provided however, that after the quarter ending March 31, 2018, if (i) there is no default, event of default or borrowing base deficiency that has occurred and is continuing, (ii) the ratio of total debt to EBITDAX as defined under the 2017 Senior Credit Facility is less than 1.75 to 1.0 and (iii) the unused borrowing base is at least 25%, then the Company can pay the interest on the Convertible Second Lien Notes in cash, at its election.

The indenture governing the Convertible Second Lien Notes (the "Indenture") contains certain covenants pertaining to us and our subsidiary, including delivery of financial reports; environmental matters; conduct of business; use of proceeds; operation and maintenance of properties; collateral and guarantee requirements; indebtedness; liens; dividends and distributions; limits on sale of assets and stock; business activities; transactions with affiliates; and changes of control.

The Indenture also contains certain financial covenants, including the maintenance of (i) a Total Proved Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.50 to 1.00 after September 30, 2017, to be determined as of January 1 and July 1 of each year and (ii) minimum liquidity requirements.

Upon issuance of the Convertible Second Lien Notes in October 2016, in accordance with accounting standards related to convertible debt instruments that may be settled in cash upon conversion as well as warrants on the debt instrument, we recorded a debt discount of $11.0 million, thereby reducing the $40.0 million carrying value upon issuance to $29.0 million and recorded an equity component of $11.0 million. The debt discount is amortized using the effective interest rate method based upon an original term through August 30, 2019. $6.1 million of debt discount remains to be amortized on the Convertible Second Lien Notes as of June 30, 2018.

As of June 30, 2018, the Company was in compliance with all covenants within the Indenture governing the Convertible Second Lien Notes.

NOTE 5—Equity

During the three months ended June 30, 2018, certain holders of the 10 year costless warrants associated with the Convertible Second Lien Notes exercised 273,437 warrants for the issuance of an equal amount of our one cent par value common stock. The Company received cash for the one cent par value for the issuance of 273,437 common shares. During the six months ended June 30, 2018, certain holders of the 10 year costless warrants associated with the Convertible Second Lien

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Notes exercised 862,812 warrants for the issuance of an equal amount of our one cent par value common stock. The Company received cash for the one cent par value for the issuance of 315,937 common shares. As of June 30, 2018, 207,500 of such warrants remain un-exercised.

During the three and six months ended June 30, 2017, holders of the 10 year costless warrants attached to the Convertible Second Lien Notes, exercised 1,375,000 warrants for the issuance of an equal amount of our one cent par value common stock. The Company received cash for the one cent par value for issuance of 625,000 common shares and the remaining common shares were issued cashless, which resulted in 564 shares repurchased by the Company and held in treasury stock. These treasury stock shares were subsequently retired.

The Company had no material vestings of its share based compensation units during the three or six months ended June 30, 2018 or 2017.

NOTE 6—Net Income (Loss) Per Common Share

Net loss applicable to common stock was used as the numerator in computing basic and diluted loss per common share for the three and six months ended June 30, 2018 and 2017. The following table sets forth information related to the computations of basic and diluted loss per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(Amounts in thousands, except per share data)			
Basic and Diluted net loss per share:				
Net loss applicable to common stock	$(2,661)	$(1,214)	$(7,985)	$(6,939)
Weighted average shares of common stock outstanding	11,629	9,670	11,424	9,381
Basic and Diluted net loss per share (1) (2)	$(0.23)	$(0.13)	$(0.70)	$(0.74)
(1) Common shares issuable on assumed conversion of share-based compensation were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive. *	491	334	346	296
(2) Common shares issuable upon conversion of the Convertible Second Lien Notes and associated warrants and unsecured claim holders were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.	3,517	4,389	3,517	4,389

* - Common shares issuable on assumed conversion of share-based compensation assumes a payout of the Company's performance share awards at 100% of the initial performance units granted (or a ratio of one unit to one common share). The range of common stock shares which may be earned ranges from zero to 250% of the initial performance units granted.

NOTE 7—Income Taxes

We recorded no income tax expense or benefit for the three or six months ended June 30, 2018. We recorded a valuation allowance for our net deferred tax asset at December 31, 2016. The valuation allowance was $86.7 million at December 31, 2017, which resulted in a net non-current deferred tax asset of $0.9 million appearing on our statement of financial position. We recorded this valuation allowance at this date after an evaluation of all available evidence (including our recent history of net operating losses in 2017 and prior years) that led to a conclusion that based upon the more-likely-than-not standard of the accounting literature, these deferred tax assets were unrecoverable. The tax benefit recorded for 2017 is due to Alternative Minimum Tax (“AMT”) credits that are expected to be recognized by the Company, which have been reduced for the anticipated sequestration. The remaining $0.9 million of AMT credits, which is less anticipated sequestration, are expected to be fully refundable in tax years 2018 - 2021 regardless of the Company's regular tax liability as a result of the repeal of the Corporate AMT under the Tax Cuts and Jobs Act. The Company no longer has a valuation allowance recorded against our estimate of refundable AMT credits. Considering the Company’s taxable income forecasts, our assessment of the realization of our deferred tax assets has not changed, and we continue to maintain a full valuation allowance for our net deferred tax assets as of June 30, 2018 aside from the deferred tax asset related to the AMT credits.

As of June 30, 2018, we have no unrecognized tax benefits. There were no significant changes to the calculation since December 31, 2017.

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On December 22, 2017, the United States enacted tax reform legislation known as the H.R.1, commonly referred to as the "Tax Cuts and Jobs Act", resulting in significant modifications to existing law. Our financial statements for the year ended December 31, 2017 and now for the three and six months ended June 30, 2018 reflect the effects of the Tax Cuts and Jobs Act which includes a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018, as well as other changes. The Company follows the guidance in SEC Staff Accounting Bulletin 118 ("SAB 118"), which provides additional clarification regarding the application of ASC Topic 740 in situations where the Company does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting for certain income tax effects of the Tax Cuts and Jobs Act for the reporting period in which the Tax Cuts and Jobs Act was enacted. SAB 118 provides for a measurement period beginning in the reporting period that includes the Tax Cuts and Jobs Act's enactment date and ending when the Company has obtained, prepared, and analyzed the information needed in order to complete the accounting requirements but in no circumstances should the measurement period extend beyond one year from the enactment date. We calculated the impact of the Tax Cuts and Jobs Act in our year ended December 31, 2017 income tax provision in accordance with our understanding of the Tax Cuts and Jobs Act and guidance available. We continue to gather and evaluate the income tax impact of the Tax Cuts and Jobs Act. The ultimate impact of the Tax Cuts and Jobs Act on our reported results in 2018 and beyond may differ, possibly materially, due to, among other things, changes in interpretations and assumptions we have made, guidance that may be issued, and other actions we may take as a result of the Tax Cuts and Jobs Act.

NOTE 8—Commodity Derivative Activities

We use commodity and financial derivative contracts to manage fluctuations in commodity prices. We are currently not designating our derivative contracts for hedge accounting. All derivative gains and losses are from our oil and natural gas derivative contracts and have been recognized in "Other income (expense)" on our Consolidated Statements of Operations.
The following table summarizes gains and losses we recognized on our oil and natural gas derivatives for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
Oil and Natural Gas Derivatives (in thousands)	2018	2017	2018	2017
Gain (loss) on commodity derivatives not designated as hedges, settled	$(156)	$4	$(541)	$147
Gain (loss) on commodity derivatives not designated as hedges, not settled	(2,018)	762	(2,614)	359
Total gain (loss) on commodity derivatives not designated as hedges	$(2,174)	$766	$(3,155)	$506

Commodity Derivative Activity
We enter into swap contracts, costless collars or other derivative agreements from time to time to manage commodity price risk for a portion of our production. Our policy is that all derivatives are approved by the Hedging Committee of the Board, and reviewed periodically by the Board.
Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Decreases in domestic crude oil and natural gas spot prices will have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis. We routinely exercise our contractual right to net realized gains against realized losses when settling with our financial counterparties. Neither our counterparties nor we require any collateral upon entering into derivative contracts. We would have been at risk of losing $0.2 million had BP Energy Company been unable to fulfill their obligations as of June 30, 2018.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

As of June 30, 2018, the open positions on our outstanding commodity derivative contracts, all of which were with JPMorgan Chase Bank, N.A. and BP Energy Company, were as follows:

Contract Type	Daily Volume	Total Volume	Fixed Price	Fair Value at June 30, 2018 (In thousands)
Oil swaps (Bbls)				
2019	312	114,025	$ 51.08	$ (1,438)
2018	350	64,400	$ 51.08	(1,216)
Total Oil				$ (2,654)
Natural Gas swaps (MMBtu)				
2020 (through March 31, 2020)	40,000	3,640,000	$ 2.814	$ (368)
2019	42,466	15,500,000	$2.814-$3.033	1,048
2018	38,500	7,084,000	$2.985-$3.033	441
Total Natural Gas				$ 1,121
Total Oil and Natural Gas				$ (1,533)

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value classified in each Level as of June 30, 2018 (in thousands). We measure the fair value of our commodity derivative contracts by applying the income approach. See Note 1—"Description of Business and Significant Accounting Policies" for our discussion regarding fair value, including inputs used and valuation techniques for determining fair values.

Description	Level 1	Level 2	Level 3	Total
Fair value of oil and natural gas derivatives - Current Assets	$ —	$ 673	$ —	$ 673
Fair value of oil and natural gas derivatives - Non-current Assets	—	447	—	447
Fair value of oil and natural gas derivatives - Current Liabilities	—	(2,045)	—	(2,045)
Fair value of oil and natural gas derivatives - Non-current Liabilities	—	(608)	—	(608)
Total	$ —	$ (1,533)	$ —	$ (1,533)

We enter into oil and natural gas derivative contracts under which we have netting arrangements with each counter party. The following table discloses and reconciles the gross amounts to the amounts as presented on the Consolidated Balance Sheets for the periods ending June 30, 2018 and December 31, 2017:

	June 30, 2018			December 31, 2017		
Fair Value of Oil and Natural Gas Derivatives (in thousands)	Gross Amount	Amount Offset	As Presented	Gross Amount	Amount Offset	As Presented
Fair value of oil and natural gas derivatives - Current Assets	$ 1,227	$ (554)	$ 673	$ 2,035	$ (1)	$ 2,034
Fair value of oil and natural gas derivatives - Non-current Assets	885	(438)	447	633	(67)	566
Fair value of oil and natural gas derivatives - Current Liabilities	(2,599)	554	(2,045)	(1,002)	—	(1,002)
Fair value of oil and natural gas derivatives - Non-current Liabilities	(1,046)	438	(608)	(585)	68	(517)
Total	$ (1,533)	$ —	$ (1,533)	$ 1,081	$ —	$ 1,081

NOTE 9—Commitments and Contingencies

We are party to various lawsuits from time to time arising in the normal course of business, including, but not limited to, royalty, contract, personal injury, and environmental claims. We have established reserves as appropriate for all such
proceedings and intend to vigorously defend these actions. Management believes, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our consolidated financial position, results of operations or liquidity.

Operating Leases—We have commitments under operating lease agreements for office space and office equipment. Total rent expense for the three months ended June 30, 2018 and 2017 was approximately $0.4 million and $0.5 million, respectively. Total rent expense for the six months ended June 30, 2018 and 2017 was approximately $0.8 million and $0.9 million, respectively.

NOTE 10—Dispositions

On May 21, 2018, the Company closed on the sale of working interests in certain oil and gas leases, including wells, facilities and leasehold acres, in our Tuscaloosa Marine Shale Trend operating area located in East and West Feliciana Parish, Louisiana for total consideration of approximately $3.3 million with an effective date of May 1, 2018. The disposition was subject to customary post-closing adjustments. The disposition was recorded as a reduction to our oil and natural gas properties (full cost method) on our Consolidated Balance Sheet.

On February 28, 2018, the Company closed, in two separate transactions, the sale of working interests in certain oil and gas leases, wells, units and facilities and certain net leasehold interests in a portion of its undeveloped acreage in the Angelina River Trend in Angelina and Nacogdoches Counties, Texas to BP America Production Company for total consideration of $23.0 million, with an effective date of January 1, 2018. The disposition was subject to customary post-closing adjustments. The disposition was recorded as a reduction to our oil and natural gas properties (full cost method) on our Consolidated Balance Sheet. The Company utilized the proceeds from these dispositions to pay down the outstanding balance of the 2017 Senior Credit Facility on March 2, 2018 and to fund our capital expenditures program.

The Company also sold other miscellaneous acreage during the three and six months ended June 30, 2018 for $0.4 million and $0.7 million, respectively, which was also recorded as a reduction to our oil and natural gas properties (full cost method) on our Consolidated Balance Sheet.

NOTE 11—Subsequent Events

On July 13, 2018, the Company entered into the First Amendment to Credit Agreement (the “First Amendment”) with the Subsidiary, as borrower, JP Morgan Chase Bank, N.A. as administrative agent, and certain lenders that are party thereto. The First Amendment amends the 2017 Senior Credit Facility. The First Amendment increased the borrowing base under the Credit Agreement from $40.0 million to $50.0 million. Additionally, the First Amendment, among other things, modifies the terms of the 2017 Senior Credit Facility to provide the Company with the right to elect to reduce the proposed Borrowing Base (as defined in the First Amendment) to a lower Draw Limit (as defined in the First Amendment) by providing notice to the lenders contemporaneously with each scheduled and interim redetermination of the Borrowing Base under the 2017 Senior Credit Facility. Upon approval by the lenders of a proposed lower Draw Limit, such Draw Limit will be the Borrowing Base until the next scheduled or interim redetermination pursuant to the terms of the 2017 Senior Credit Facility, as amended by the First Amendment.

Item 2—Management’s Discussion and Analysis of Financial Condition and Results of Operations

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

We have made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with our management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), concerning our operations, economic performance and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and natural gas properties, marketing and midstream activities, and also include those statements accompanied by or that otherwise include the words “may,” “could,” “believes,” “expects,” “anticipates,” “intends,” “estimates,” “projects,” “pr “target,” “goal,” “plans,” “objective,” “potential,” “should,” or similar expressions or variations on such expressions that conve the uncertainty of future events or outcomes. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to be correct. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made; we undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following:

- the market prices of oil and natural gas;
- volatility in the commodity-futures market;
- financial market conditions and availability of capital;
- future cash flows, credit availability and borrowings;
- sources of funding for exploration and development;
- our financial condition;
- our ability to repay our debt;
- the securities, capital or credit markets;
- planned capital expenditures;
- future drilling activity;
- uncertainties about the estimated quantities of our oil and natural gas reserves;
- production;
- hedging arrangements;
- litigation matters;
- pursuit of potential future acquisition opportunities;
- general economic conditions, either nationally or in the jurisdictions in which we are doing business;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulation, drilling and permitting regulations, derivatives reform, changes in state and federal corporate taxes, environmental regulation, environmental risks and liability under federal, state and foreign and local environmental laws and regulations;
- the creditworthiness of our financial counterparties and operation partners; and
- other factors discussed below and elsewhere in this Quarterly Report on Form 10-Q and in our other public filings, press releases and discussions with our management.

For additional information regarding known material factors that could cause our actual results to differ from projected results please read the rest of this report and Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2017.

Overview

Goodrich Petroleum Corporation (“Goodrich” and, together with its wholly-owned subsidiary, Goodrich Petroleum Company, L.L.C. (the “Subsidiary”), “we,” “our,” or the “Company”) is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in (i) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend, (ii) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale Trend (“TMS”), and (iii) South Texas, which includes the Eagle Ford Shale Trend.

We seek to increase shareholder value by growing our oil and natural gas reserves, production, revenues and cash flow from operating activities (“operating cash flow”). In our opinion, on a long term basis, growth in oil and natural gas reserves, cash flow and production on a cost-effective basis are the most important indicators of performance success for an independent oil and natural gas company.

We strive to increase our oil and natural gas reserves, production and cash flow through exploration and development activities. We develop an annual capital expenditure budget, which is reviewed and approved by our Board of Directors (the “Board”) on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow, commodity prices for oil and natural gas and available sources of external financing, such as bank debt, asset divestitures, issuances of debt and equity securities, and strategic joint ventures, when establishing our capital expenditure budget.

We place primary emphasis on our operating cash flow in managing our business. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures, such as net income, because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized derivative gains (losses), non-cash general and administrative expenses and impairments.

Our revenues and operating cash flow depend on the successful development of our inventory of capital projects with available capital, the volume and timing of our production, as well as prevailing commodity prices for oil and natural gas. Commodity prices are largely beyond our control; however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our revenues and operating cash flow.

Primary Operating Areas

Haynesville Shale Trend

Our development acreage in the Haynesville Shale Trend is primarily centered in DeSoto, Caddo and Red River parishes, Louisiana. We held approximately 45,900 gross (21,800 net) acres as of June 30, 2018 producing from and prospective for the Haynesville Shale Trend. Our net production volumes from our Haynesville Shale Trend wells represented approximately 94% of our total equivalent production on a Mcfe basis for the second quarter of 2018. We completed and produced 4 gross (2.0 net) new wells in the second quarter of 2018 and have 7 gross (2.8 net) wells in the drilling and completion phases as of June 30, 2018. We plan to focus all of our 2018 drilling efforts in the Haynesville Shale Trend.

Tuscaloosa Marine Shale Trend

We held approximately 60,000 gross (43,100 net) acres in the TMS as of June 30, 2018. We have 2 gross (1.7 net) TMS wells drilled and awaiting completion. During the second quarter of 2018, we sold a portion of our interest in the western area of our TMS acreage position in East and West Feliciana Parishes, Louisiana for $3.3 million. Our net production volumes from our TMS wells represented approximately 6% of our total equivalent production on a Mcfe basis and approximately 100% of our total oil production for the second quarter of 2018. Despite making no capital expenditures, we are seeking to maintain production through strategic expense workover operations in the TMS.

Eagle Ford Shale Trend

We hold approximately 14,000 net acres of undeveloped leasehold in the Eagle Ford Shale Trend all of which is prospective for future development or sale.

Results of Operations

The items that had the most material financial effect on our net loss of $2.7 million for the three months ended June 30, 2018 were a $2.2 million loss on our commodity derivatives not designated as hedges, $1.4 million share-based compensation included in general and administrative expense and $2.7 million in interest expense. All but $0.2 million of these items are non-cash expenses. The items that had the most material financial effect on our net loss of $8.0 million for the six months ended June 30, 2018 were a $3.2 million loss on our commodity derivatives not designated as hedges, $3.1 million share-based compensation included in general and administrative expense and $5.4 million in interest expense. All but $0.8 million of these items are non-cash expenses.

The item that had the most material financial effect on our net loss of $1.2 million for the three months ended June 30, 2017 was lease operating expense. Lease operating expense in the period included $0.7 million in workover expenses incurred in our effort to increase production volumes after having curtailed such expenditures while in bankruptcy during the previous year. The item that had the most material financial effect on our net loss of $6.9 million for the six months ended June 30, 2017 was lease operating expense. Lease operating expense in the period included $2.9 million in workover expenses incurred in our effort to increase production volumes after having curtailed such expenditures while in bankruptcy during the previous year.

The following table reflects our summary operating information for the periods presented in thousands, except for price and volume data. Because of normal production declines, increased or decreased drilling activity and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as indicative of future results.

Revenues from Operations

	Three Months Ended June 30,				Six Months Ended June 30,			
(In thousands, except for price and average daily production data)	2018	2017	Variance		2018	2017	Variance	
Revenues:								
Natural gas	$13,816	$8,086	$5,730	71 %	$21,717	$13,387	$8,330	62 %
Oil and condensate	3,968	4,029	(61)	(2)%	7,910	8,139	(229)	(3)%
Natural gas, oil and condensate	17,784	12,115	5,669	47 %	29,627	21,526	8,101	38 %
Net Production:								
Natural gas (MMcf)	5,170	2,795	2,375	85 %	8,122	4,628	3,494	75 %
Oil and condensate (MBbls)	57	84	(27)	(32)%	118	166	(48)	(29)%
Total (Mmcfe)	5,513	3,299	2,214	67 %	8,829	5,623	3,206	57 %
Average daily production (Mcfe/d)	60,582	36,253	24,329	67 %	48,779	31,066	17,713	57 %
Average realized sales price per unit:								
Natural gas (per Mcf)	$2.67	$2.89	$(0.22)	(8)%	$2.67	$2.89	$(0.22)	(8)%
Natural gas (per Mcf) including the effect of realized gains/losses on derivatives	$2.76	$2.89	$(0.13)	(4)%	$2.74	$2.92	$(0.18)	(6)%
Oil and condensate (per Bbl)	$69.39	$47.96	$21.43	45 %	$67.12	$49.03	$18.09	37 %
Oil and condensate (per Bbl) including the effect of realized losses on derivatives	$58.69	$47.96	$10.73	22 %	$58.33	$49.03	$9.30	19 %
Average realized price (per Mcfe)	$3.23	$3.67	$(0.44)	(12)%	$3.36	$3.83	$(0.47)	(12)%

Natural gas, oil and condensate revenues increased by $5.7 million and $8.1 million for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. The increase was primarily driven by higher natural gas production and higher realized oil prices offset by lower oil production and lower natural gas prices. The increase in natural gas production volumes is attributed to four Haynesville Shale Trend wells completed in the second quarter of 2018 and the continued production of five Haynesville Shale Trend wells completed in 2017 and the first quarter of 2018. We are concentrating our operational activities and resources on increasing natural gas production in the Haynesville Shale Trend. For the three and six months ended June 30, 2018, 78% and 73%, respectively, of our oil and natural gas revenue was attributable to natural gas sales compared to 67% and 62% for the three and six months ended June 30, 2017, respectively.

Operating Expenses

As described below, total operating expenses increased $3.7 million and $3.9 million for the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. The increase in total operating expenses for the three months ended June 30, 2018 was primarily due to increased depreciation, depletion and amortization expense of $2.5 million and increased general and administrative expense of $1.0 million. The increase in total operating expenses for the six months ended June 30, 2018 was primarily due to increased depreciation, depletion and amortization expense of $3.6 million, increased general and administrative expense of $1.8 million, and increased transportation expense of $0.4 million offset by decreased lease operating expense of $2.2 million.

	Three Months Ended June 30,				Six Months Ended June 30,			
Operating Expenses (in thousands)	2018	2017	Variance		2018	2017	Variance	
Lease operating expenses	$2,465	$2,950	$(485)	(16)%	$5,031	$7,261	$(2,230)	(31)%
Production and other taxes	669	424	245	58 %	1,309	1,083	226	21 %
Operating Expenses per Mcfe								
Lease operating expenses	$0.45	$0.89	$(0.44)	(49)%	$0.57	$1.29	$(0.72)	(56)%
Production and other taxes	$0.12	$0.13	$(0.01)	(8)%	$0.15	$0.19	$(0.04)	(21)%

Lease Operating Expense

Lease operating expense decreased $0.5 million and $2.2 million during the three and six months ended June 30, 2018, respectively, compared to the same periods in 2017. The decrease is substantially attributed to a decrease in workover expense and lower per unit costs for new Haynesville Shale Trend wells for the three and six months ended June 30, 2018 compared to the same period in 2017, offset by increased costs due to an increased well count for the three and six months ended June 30, 2018. We incurred $0.7 million in workover cost for the three months ended June 30, 2017 and only $0.3 million for the three months ended June 30, 2018. We incurred $2.9 million in workover cost for the six months ended June 30, 2017 and only $0.6 million for the six months ended June 30, 2018. The majority of the workover expense incurred in the second quarter of 2018 is attributed to our TMS wells in the effort to maintain our oil production. Lease operating expense exclusive of workover expense on a per unit basis was $0.40 and $0.67 per Mcfe for the three months ended June 30, 2018 and 2017, respectively, and $0.50 and $0.78 for the six months ended June 30, 2018 and 2017, respectively. We expect per unit lease operating expense to continue to decrease as we increase production from the Haynesville Shale Trend, which carries a lower per unit lease operating expense than the Company’s current per unit rate.

Production and Other Taxes

Production and other taxes, which includes severance and ad valorem taxes, has increased by $0.2 million for the three and six months ended June 30, 2018 as compared to the same periods in 2017. Severance taxes for the three and six months ended June 30, 2018 were $0.4 million and $0.8 million, respectively, and ad valorem taxes for the three and six months ended June 30, 2018 were $0.3 million and $0.5 million, respectively. Severance taxes for the three and six months ended June 30, 2017 were $0.5 million and $0.8 million, respectively, and ad valorem taxes were negligible and $0.3 million for the three and six months ended June 30, 2017, respectively.

Severance taxes decreased less than $0.1 million for the three months ended June 30, 2018 as compared with the same period in 2017, reflecting decreased oil production volumes offset by expiration of tax exemptions on certain wells in Mississippi and Louisiana. Severance taxes increased less than $0.1 million for the six months ended June 30, 2018 as compared with the same period in 2017, reflecting the expiration of tax exemptions on certain wells in Mississippi and Louisiana offset by decreased oil production volumes.

The State of Mississippi has enacted an exemption from the existing 6.0% severance tax for horizontal wells drilled after July 1, 2013 with production commencing before July 1, 2018, which is partially offset by a 1.3% local severance tax on such wells. The tax exemption on all of our Mississippi oil wells has expired.

The State of Louisiana has also enacted an exemption from the existing 12.5% severance tax on oil and from the $0.098 per Mcf (through June 30, 2017) and $0.11 per Mcf (from July 1, 2017 through June 30, 2018) severance tax on natural gas for horizontal wells with production commencing after July 31, 1994. The exemption is applicable until the earlier of (i) 24 months from the date of first sale of production or (ii) payout of the well. Our recently drilled Haynesville Shale Trend wells in Northwest Louisiana are benefiting from this exemption.

Ad valorem taxes increased by $0.3 million and $0.2 million for the three and six months ended June 30, 2018, respectively, as compared to the same periods in 2017 due to no receipt of refunds for ad valorem taxes in 2018 as were received in 2017.

	Three Months Ended June 30,				Six Months Ended June 30,			
Operating Expenses (in thousands):	2018	2017	Variance		2018	2017	Variance	
Transportation and processing	$2,086	$1,868	$218	12 %	$3,398	$3,044	$354	12 %
Depreciation, depletion and amortization	5,560	3,083	2,477	80 %	9,012	5,377	3,635	68 %
General and administrative	4,803	3,772	1,031	27 %	9,999	8,235	1,764	21 %
Other	165	—	165	100 %	165	—	165	100 %
Operating Expenses per Mcfe								
Transportation and processing	$0.38	$0.57	$(0.19)	(33)%	$0.38	$0.54	$(0.16)	(30)%
Depreciation, depletion and amortization	$1.01	$0.93	$0.08	9 %	$1.02	$0.96	$0.06	6 %
General and administrative	$0.87	$1.14	$(0.27)	(24)%	$1.13	$1.46	$(0.33)	(23)%
Other	$0.03	$—	$0.03	100 %	$0.02	$—	$0.02	100 %

Transportation and Processing

Transportation and processing expense for the three and six months ended June 30, 2018 increased while per unit expense decreased compared to the same periods in 2017, reflecting increased production from our operated Haynesville Shale Trend wells. Our natural gas volumes from our operated wells generally carry less transportation cost than from wells we do not operate. Our per unit transportation cost will continue to decrease as we increase our operated natural gas production.

Depreciation, Depletion and Amortization (“DD&A”)

DD&A expense is calculated on the Full Cost Method of Accounting using the units of production (the “UOP”) method. The increase in DD&A was attributed primarily to increased production for the three and six months ended June 30, 2018 as compared to the same periods in 2017.

General and Administrative (“G&A”)

We recorded $4.8 million and $10.0 million in G&A expense for the three and six months ended June 30, 2018, respectively, which included non-cash expenses of $1.4 million and $3.1 million, respectively, for share based compensation. G&A expense increased for the three and six months ended June 30, 2018 by $1.0 million and $1.8 million, respectively, compared to the same periods in 2017 primarily due to increased share based compensation expense and other employee related expenses including employee benefits costs and accrued performance bonuses.

We recorded $3.8 million and $8.2 million in G&A expense in the three and six months ended June 30, 2017, respectively, which included non-cash expenses of (i) $1.0 million and $2.0 million, respectively, for share based compensation, (ii) $0.7 million and $1.4 million, respectively, in performance bonuses of which a majority were compensated in common stock and (iii) $0.1 million and $0.3 million, respectively, of office rent amortization.

Other Operating Expense

We recorded $0.2 million in Other operating expense for the three and six months ended June 30, 2018, which includes a $0.2 million loss on the sale of inventory.

Other Income (Expense)

	Three Months Ended June 30,				Six Months Ended June 30,			
Other income (expense) (in thousands):	2018	2017	Variance		2018	2017	Variance	
Interest expense	$(2,732)	$(2,360)	$(372)	16 %	$(5,405)	$(4,539)	$(866)	19 %
Interest income and other	116	12	104	867 %	109	21	88	419 %
Gain (loss) on commodity derivatives not designated as hedges	(2,174)	766	(2,940)	(384)%	(3,155)	506	(3,661)	(724)%
Average funded borrowings adjusted for debt discount and accretion	$43,401	$50,488	$(7,087)	(14)%	$46,875	$49,490	$(2,615)	(5)%
Average funded borrowings	$50,194	$60,165	$(9,971)	(17)%	$54,119	$59,459	$(5,340)	(9)%

Interest Expense

Interest expense for the three and six months ended June 30, 2018 reflected cash interest of $0.1 million and $0.2 million, respectively, incurred on the 2017 Senior Credit Facility (as defined below) and non-cash interest of $2.6 million and $5.2 million, respectively, incurred on the Company's 13.50% Convertible Second Lien Senior Secured Notes due 2019 (the “Convertible Second Lien Notes”), which included $1.6 million and $3.2 million, respectively, of paid in-kind interest and $1.0 million and $1.8 million, respectively, of amortization of debt discount.

Interest expense for the three and six months ended June 30, 2017 reflected cash interest of $0.3 million and $0.5 million, respectively, incurred on the Exit Credit Facility and non-cash interest of $2.1 million and $4.0 million, respectively, incurred on the Convertible Second Lien Notes, which included the paid in-kind interest and amortization of debt discount.

Gain (Loss) on Commodity Derivatives Not Designated as Hedges

Loss on commodity derivatives not designated as hedges for the three and six months ended June 30, 2018 was comprised of an unrealized loss of $2.0 million and $2.6 million, respectively, representing the change of the fair value of our open natural gas and oil derivative contracts, as well as a loss of $0.2 million and $0.5 million, respectively, on cash settlement of natural gas and oil derivative contracts.

Gain on commodity derivatives not designated as hedges for the three months ended June 30, 2017 was comprised of an unrealized gain of $0.8 million, representing the change of the fair value of our natural gas derivative contracts, as well as a de minimis gain on cash settlement. Gain on commodity derivatives not designated as hedges for the six months ended June 30, 2017 was comprised of an unrealized gain of $0.4 million, representing the change of the fair value of our natural gas derivative contracts, as well as a $0.1 million gain on cash settlement.

Reorganization gain (loss), net

Reorganization gain (loss), net for the three and six months ended June 30, 2018 was less than $0.1 million gain and a $0.3 million loss, respectfully. The claims settled in the second quarter of 2018 resulted in a net reorganization gain of $0.3 million which was offset by legal fees incurred on the claims settlements and the final trustee fee of $0.2 million. We settled all remaining claims and closed our bankruptcy case in the second quarter of 2018. One claim has until September 27, 2018 to file a petition with the U.S. Supreme Court to appeal.

Income Tax Benefit

We recorded no income tax expense or benefit for the three or six months ended June 30, 2018. We recorded a valuation allowance for our net deferred tax asset at December 31, 2016. The valuation allowance was $86.7 million at December 31, 2017, which resulted in a net non-current deferred tax asset of $0.9 million appearing on our statement of financial position. We recorded this valuation allowance at this date after an evaluation of all available evidence (including our recent history of net operating losses in 2017 and prior years) that led to a conclusion that based upon the more-likely-than-not standard of the accounting literature, these deferred tax assets were unrecoverable. The tax benefit recorded for 2017 is due to Alternative Minimum Tax (“AMT”) credits that are expected to be recognized by the Company, which have been reduced for the anticipated sequestration. The remaining $0.9 million of AMT credits, which is less anticipated sequestration, are expected to be fully refundable in tax years 2018 - 2021 regardless of the Company's regular tax liability as a result of the repeal of the Corporate AMT under the Tax Cuts and Jobs Act. The Company no longer has a valuation allowance recorded against our estimate of refundable AMT credits. Considering the Company’s taxable income forecasts, our assessment of the realization of our deferred tax assets has not changed, and we continue to maintain a full valuation allowance for our net deferred tax assets as of June 30, 2018 aside from the deferred tax asset related to the AMT credits.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-United States Generally Accepted Accounting Principle ("US GAAP") financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines Adjusted EBITDA as earnings before interest expense, income tax, DD&A, share based compensation expense and impairment of oil and natural gas properties. In calculating Adjusted EBITDA, mark-to-market gains/losses on commodity derivatives not designated as hedges are also excluded. Other excluded items include interest income, reorganization and other non-recurring income and expense. Adjusted EBITDA is not a measure of net income (loss) as determined by US GAAP. Adjusted EBITDA should not be considered an alternative to net income (loss), as defined by US GAAP. The following table presents a reconciliation of the non-US GAAP measure of Adjusted EBITDA to the US GAAP measure of net income (loss), its most directly comparable measure presented in accordance with US GAAP:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2018	2017	2018	2017
Net loss (US GAAP)	$(2,661)	$(1,214)	$(7,985)	$(6,939)
Interest expense	2,732	2,360	5,405	4,539
Depreciation, depletion and amortization	5,560	3,083	9,012	5,377
Share based compensation expense (non-cash)	1,491	1,651	3,167	3,379
Mark-to-market (gain) loss on commodity derivatives not designated as hedges	2,018	(762)	2,614	(359)
Other items (1)	(240)	(12)	98	(216)
Adjusted EBITDA	$8,900	$5,106	$12,311	$5,781

(1) Other items include interest income, reorganization and other non-recurring income and expense.

Management believes that this non-US GAAP financial measure provides useful information to investors because it is monitored and used by our management and widely used by professional research analysts in the valuation and investment recommendations of companies within the oil and natural gas exploration and production industry. Our computations of Adjusted EBITDA/EBITDAX are defined in our 2017 Senior Credit Facility Agreement (for 2018), Exit Credit Facility Agreement (for 2017) and the indenture governing our Convertible Second Lien Notes, consequently it may not be comparable to other similarly totaled measures of other companies.

Liquidity and Capital Resources

Overview

Our primary sources of cash during the three months ended June 30, 2018 were cash on hand, cash from operating activities, borrowings under our 2017 Senior Credit Facility and proceeds from the sale of assets. We used cash primarily to fund capital expenditures. We currently plan to fund our operations and capital expenditures for the remainder of 2018 through a combination of cash on hand, cash from operating activities and borrowings under our 2017 Senior Credit Facility, although we may from time to time consider the funding alternatives described below.

On October 17, 2017, we entered into the Amended and Restated Senior Secured Revolving Credit Facility ("Credit Agreement") with the Subsidiary, as borrower, JPMorgan Chase Bank, N.A. as administrative agent, and certain lenders that are party thereto, which provides for revolving loans of up to the borrowing base then in effect (the "2017 Senior Credit Facility"). Total lender commitments under the 2017 Senior Credit Facility are $250 million. The 2017

Senior Credit Facility matures on a) October 17, 2021 or b) if the Convertible Second Lien Notes have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by September 30, 2019, then September 30, 2019. Revolving borrowings under the 2017 Senior Credit Facility are limited to, and subject to periodic redeterminations, of the borrowing base. The initial borrowing base was $40 million. Pursuant to the terms of the 2017 Senior Credit Facility, borrowing base redeterminations will be on a semi-annual basis on or about March 1st and September 1st of each calendar year. JPMorgan Chase Bank, N.A. is the lead lender and administrative agent under the Senior Credit Facility.

We exited the second quarter of 2018 with cash of $1.7 million and $6.0 million outstanding borrowings with $34.0 million of availability under the 2017 Senior Credit Facility. Effective July 13, 2018, our borrowing base was increased to $60.0 million with an elected draw limit of $50.0 million in recognition of the limitation set forth in the Convertible Second Lien Notes. This increase in our borrowing base constituted the scheduled redetermination for spring 2018 under the 2017 Senior Credit Facility. Due to the timing of payment of our capital expenditures and timing of borrowings under our 2017 Senior Credit Facility, we reflected a working capital deficit of $22.2 million as of June 30, 2018. To the extent we operate with a working capital deficit, we expect such deficit to be offset by liquidity available under our 2017 Senior Credit Facility.

Our total capital expenditure budget for 2018 is expected to range between $85 million to $95 million. We plan to focus all of our 2018 drilling efforts in the Haynesville Shale Trend.

We continuously monitor our leverage position and coordinate our capital program with our expected cash flows and repayment of our projected debt. We will continue to evaluate funding alternatives as needed.

Alternatives available to us include:
- sale of non-core assets;
- joint venture partnerships in our TMS, Eagle Ford Shale Trend, and/or core Haynesville Shale Trend acreage; and
- issuance of debt or equity securities.

We have supported our cash flows with derivative contracts that covered approximately 44% and 50% of our natural gas sales volumes for the three and six months ended June 30, 2018, respectively and 64% and 61% of our oil sales volumes for the three and six months ended June 30, 2018, respectively. For additional information on our derivative instruments see Note 8—"Commodity Derivative Activities" in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Cash Flows

The following table presents our comparative cash flow summary for the periods reported (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Cash flow statement information:				
Net cash:				
Provided by operating activities	$6,399	$10,863	$12,655	$15,528
Used in investing activities	(20,399)	(14,135)	(26,180)	(17,519)
Provided by (used in) financing activities	5,998	(266)	(10,738)	(448)
Decrease in cash and cash equivalents	$(8,002)	$(3,538)	$(24,263)	$(2,439)

Operating activities: Production from our wells, the price of oil and natural gas and operating costs represent the main drivers behind our cash flow from operations for both the three and six months ended June 30, 2018 and June 30, 2017. Changes in working capital and net cash settlements related to our derivative contracts also impact cash flows. Net cash provided by operating activities for the three months ended June 30, 2018 was $6.4 million including operating cash flows before working capital changes of $9.2 million reduced by net cash payments of $0.2 million in settlement of derivative contracts. Net cash provided by operating activities for the three months ended June 30, 2017 was $10.9 million including operating cash flows before working capital changes of $4.8 million. Net cash provided by operating activities for the six months ended June 30, 2018 was $12.7 million including operating cash flows before working capital changes of $12.5 million reduced by net cash payments of $0.5 million in settlement of derivative contracts. Net cash provided by operating activities for the six months ended June 30, 2017 was $15.5 million including operating cash flows before working capital changes of $5.3 million including net cash receipts of

$0.1 million in settlement of derivatives.

Investing activities: Net cash used in investing activities was $26.2 million for the six months ended June 30, 2018. We booked $52.0 million in capital expenditures, of which we paid out cash amounts totaling $53.1 million for drilling and development operations during the period. The difference is attributed to utilizing $0.7 million of cash calls paid in previous periods, utilizing $0.5 million from materials inventory, capitalized non-cash internal cost of $0.4 million, and capitalized net asset retirement obligations of $0.1 million offset by a net $2.8 million decrease in the capital expenditure accrual. The period also reflects the receipt of $26.9 million in proceeds from the sales of non-producing mineral interests and producing wells in non-core areas. We conducted drilling operations on 14 wells and completed 7 wells all in the Haynesville Shale Trend during the six month ended June 30, 2018, capitalizing $1.6 million in internal costs.

Financing activities: Net cash used in financing activities for the three and six months ended June 30, 2018 primarily reflects the borrowings and payoff of borrowings outstanding under our 2017 Senior Credit Facility.

Debt consisted of the following balances as of the dates indicated (in thousands):

	June 30, 2018		December 31, 2017	
	Principal	Carrying Amount	Principal	Carrying Amount
2017 Senior Credit Facility	$6,000	$6,000	$16,723	$16,723
Convertible Second Lien Notes (1)	50,224	44,080	47,015	39,002
Total debt	$56,224	$50,080	$63,738	$55,725

(1) The debt discount is being amortized using the effective interest rate method based upon a maturity date of August 30, 2019. The principal includes $10.2 million and $7.0 million of paid in-kind interest at June 30, 2018 and December 31, 2017, respectively. The carrying value includes $6.1 million and $8.0 million of unamortized debt discount at June 30, 2018 and December 31, 2017, respectively.

For additional information on our financing activities, see Note 4—"Debt" in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Off-Balance Sheet Arrangements

We do not currently have any off-balance sheet arrangements for any purpose.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on consolidated financial statements, which were prepared in accordance with US GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We believe that certain accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements. Our Annual Report on Form 10-K for the year ended December 31, 2017, includes a discussion of our critical accounting policies and there have been no material changes to such policies during the three months ended June 30, 2018.

Item 3—Quantitative and Qualitative Disclosures about Market Risk

Our primary market risks are attributable to fluctuations in commodity prices and interest rates. These fluctuations can affect revenues and cash flow from operating, investing and financing activities. Our risk-management policies provide for the use of derivative instruments to manage these risks. The types of derivative instruments we utilize include futures, swaps, options and fixed-price physical-delivery contracts. The volume of commodity derivative instruments we utilize may vary from year to year and is governed by risk-management policies with levels of authority delegated by our Board. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and we may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements.

For information regarding our accounting policies and additional information related to our derivative and financial instruments, see Note 1—"Description of Business and Significant Accounting Policies", Note 4—"Debt" and Note 8—"Commodity Derivative Activities" in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Quarterly Report on Form 10-Q.

Commodity Price Risk

Our most significant market risk relates to fluctuations in crude oil and natural gas prices. Management expects the prices of these commodities to remain volatile and unpredictable. As these prices decline or rise significantly, revenues and cash flow will also decline or rise significantly. In addition, a non-cash write-down of our oil and natural gas properties may be required if future commodity prices experience a sustained and significant decline. We do not enter into derivatives instruments for trading purposes. Utilizing actual derivative contractual volumes, a hypothetical increase of 10% in the underlying commodity prices would have changed the derivative gas asset position to a liability position with a change of $7.0 million and increased the derivative oil liability position by $1.1 million as of June 30, 2018. Likewise, a hypothetical decrease of 10% in the underlying commodity prices would have increased the gas asset position by $7.3 million and decreased the derivative oil liability by $1.1 million as of June 30, 2018. Furthermore, a gain or loss on derivatives would have been substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instruments.

Adoption of Comprehensive Financial Reform

The adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Item 1A, “Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

Item 4—Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission and that any material information relating to us is recorded, processed, summarized and reported to our management including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of June 30, 2018, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1—Legal Proceedings

A discussion of our current legal proceedings is set forth in Part I, Item 1 under Note 9—“Commitments and Contingencies” to the Notes to Consolidated Financial Statements in this Quarterly Report on Form 10-Q.

As of June 30, 2018, we did not have any material outstanding and pending litigation.

Item 1A—Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially affect our business, financial condition or future results.

Item 6—Exhibits

3.1	Second Amended and Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated October 12, 2016, (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016).
3.2	Second Amended and Restated Bylaws of Goodrich Petroleum Corporation, dated October 12, 2016, (Incorporated by reference to Exhibit 4.2 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016).
10.1*	First Amendment to Credit Agreement, dated as of July 13, 2018, by and among Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto.
31.1*	Certification by Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification by Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification by Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification by Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith

** Furnished herewith

SIGNATURES

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

GOODRICH PETROLEUM CORPORATION
(Registrant)

Date: August 7, 2018 By: /S/ Walter G. Goodrich
Walter G. Goodrich
Chairman & Chief Executive Officer

Date: August 7, 2018 By: /S/ Robert T. Barker
Robert T. Barker
Senior Vice President, Controller, Chief Accounting Officer and Chief Financial Officer