GOODRICH PETROLEUM CORP
Form 10-Q
August 04, 2017

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, 2017
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 7(a)(2)(B) of the Securities 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 10,538,513 shares of common stock outstanding on August 4, 2017.

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, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$34,411	$36,850
Restricted cash	600	—
Accounts receivable, trade and other, net of allowance	241	1,998
Accrued oil and natural gas revenue	5,768	3,142
Inventory	3,507	4,125
Prepaid expenses and other	971	755
Total current assets	45,498	46,870
PROPERTY AND EQUIPMENT:		
Unevaluated properties	11,554	24,206
Oil and natural gas properties (full cost method)	93,998	60,936
Furniture, fixtures and equipment	1,003	984
	106,555	86,126
Less: Accumulated depletion, depreciation and amortization	(9,271)	(4,006)
Net property and equipment	97,284	82,120
Other	571	322
TOTAL ASSETS	$143,353	$129,312
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$25,603	$14,392
Accrued liabilities	7,816	3,882
Total current liabilities	33,419	18,274
Long term debt, net	51,180	47,205
Accrued abandonment cost	3,109	2,933
Total liabilities	87,708	68,412
Commitments and contingencies (See Note 8)		
STOCKHOLDERS' EQUITY:		
Common stock: $0.01 par value, 75,000,000 shares authorized, and 10,483,826 shares issued and outstanding at June 30, 2017 and $0.01 par value, 75,000,000 shares authorized, and 9,108,826 shares issued and outstanding at December 31, 2016	105	91
Treasury stock (564 and zero shares, respectively)	(7)	—
Additional paid in capital	66,793	65,116
Accumulated deficit	(11,246)	(4,307)
Total stockholders' equity	55,645	60,900
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$143,353	$129,312

See accompanying notes to consolidated financial statements.

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

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016
REVENUES:				
Oil and natural gas revenues	$ 12,115	$ 6,417	$ 21,526	$ 12,881
Other	350	(78)	352	(297)
	12,465	6,339	21,878	12,584
OPERATING EXPENSES:				
Lease operating expense	2,950	1,957	7,261	4,293
Production and other taxes	424	677	1,083	1,416
Transportation and processing	1,868	448	3,044	879
Depreciation, depletion and amortization	3,083	2,541	5,377	5,686
Exploration	—	289	—	486
General and administrative	3,772	3,720	8,235	10,084
Gain on sale of assets	—	2	—	(835)
	12,097	9,634	25,000	22,009
Operating income (loss)	368	(3,295)	(3,122)	(9,425)
OTHER INCOME (EXPENSE):				
Interest expense	(2,360)	(1,626)	(4,539)	(9,939)
Interest income and other	12	58	21	58
Gain on derivatives not designated as hedges	766	6	506	30
	(1,582)	(1,562)	(4,012)	(9,851)
Restructuring	—	(814)		(5,128)
Reorganization items, net	—	442	195	442
Loss before income taxes	(1,214)	(5,229)	(6,939)	(23,962)
Income tax benefit	—	—	—	—
Net loss	(1,214)	(5,229)	(6,939)	(23,962)
Preferred stock, net	—	5,117	—	6,121
Net loss applicable to common stock	$ (1,214)	$ (10,346)	$ (6,939)	$ (30,083)
PER COMMON SHARE				
Net loss applicable to common stock - basic	$ (0.13)	$ (0.13)	$ (0.74)	$ (0.39)
Net loss applicable to common stock - diluted	$ (0.13)	$ (0.13)	$ (0.74)	$ (0.39)
Weighted average common shares outstanding - basic	9,670	77,892	9,381	76,251
Weighted average common shares outstanding - diluted	9,670	77,892	9,381	76,251

See accompanying notes to consolidated financial statements.

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

	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (6,939)	$ (23,962)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depletion, depreciation and amortization	5,377	5,686
Gain on commodity derivatives not designated as hedges	(506)	(30)
Net cash received in settlement of commodity derivative instruments	147	—
Amortization of leasehold costs	—	52
Share based compensation (non-cash)	3,379	2,171
Gain on sale of assets	—	(835)
Embedded derivative	—	(4,738)
Amortization of finance cost, debt discount, paid in-kind interest and accretion	3,975	5,352
Materials inventory write-down	—	156
Gain from material transfers	(73)	—
Reorganization items, net	(78)	(2,572)
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	1,757	324
Accrued oil and natural gas revenue	(2,626)	294
Inventory	—	(462)
Prepaid expenses and other	(400)	1,006
Restricted cash	(600)	—
Accounts payable	11,211	(3,008)
Accrued liabilities	904	8,252
Net cash provided by (used in) operating activities	15,528	(12,314)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(17,519)	(1,760)
Proceeds from sale of assets	—	289
Net cash used in investing activities	(17,519)	(1,471)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from bank borrowings	—	13,000
Net payments related to Convertible Second Lien Notes	(170)	—
Note conversions	—	(804)
Registration costs	(278)	(116)
Other	—	(5)
Net cash (used in) provided by financing activities	(448)	12,075
DECREASE IN CASH AND CASH EQUIVALENTS	(2,439)	(1,710)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	36,850	11,782
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 34,411	$ 10,072
Supplemental disclosures of cash flow information:		
Cash paid for Reorganization items, net	$ 828	$ 20

Cash paid for Interest	$ 581	$ 1,025

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 (together with its 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, 2016. Operating results for the three and six months ended June 30, 2017 are not necessarily indicative of the results that may be expected for the full year or for any interim period. Certain data in prior periods’ financial statements have been adjusted to conform to the presentation of the current period.

Fresh Start Accounting—We applied fresh start accounting upon emergence from bankruptcy on October 12, 2016 (the “Effective Date”). This resulted in the Company becoming a new entity for financial reporting purposes. Upon adoption of fresh start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. As a result, our consolidated statements of operations subsequent to the Effective Date are not comparable to our consolidated statement of operations prior to the Effective Date. Our consolidated financial statements and related footnotes are presented in a format that illustrates the lack of comparability between amounts presented on or after the Effective Date and dates prior. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

All references made to "Successor" or "Successor Company" relate to the Company on and subsequent to the Effective Date. References to the “Successor" in this quarterly report relate to the periods after the Effective Date, which includes the first two quarters of 2017. References to "Predecessor" or “Predecessor Company” in this quarterly report refer to the Company prior to the Effective Date, which includes the first two quarters of 2016.

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.

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.

Restricted Cash—As of June 30, 2017, the Company had $0.6 million in restricted cash held as collateral for the issuance of a letter of credit in connection with a natural gas gathering agreement.

Accounts Payable—Accounts payable consisted of the following amounts as of June 30, 2017 and December 31, 2016:

(In thousands)	June 30, 2017	December 31, 2016
Trade payables	$11,963	$ 2,004
Revenue payable	13,256	11,296
Prepayments from partners	147	965
Miscellaneous payables	237	127
Total accounts payable	$25,603	$ 14,392

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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. Upon emergence from bankruptcy, we elected to adopt the Full Cost Method.

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 and six months ended June 30, 2017, we transferred $1.9 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.

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, 2017.

Impairment—Prior to the Effective Date, under the Successful Efforts Method of Accounting, we periodically assessed our long-lived assets recorded in oil and natural gas properties on the Consolidated Balance Sheets to ensure that they were not overstated or carried in excess of fair value, which was computed using Level 3 inputs such as discounted cash flow models or valuations. Significant Level 3 assumptions associated with discounted cash flow models or valuations used in the impairment evaluation included estimates of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. An evaluation was performed on a field-by-field basis at least annually or whenever changes in facts and circumstances indicated that our oil and natural gas properties may be impaired.

To determine if a field was impaired, we compared the carrying value of the field to the undiscounted future net cash flows by applying management's estimates of proved reserves, future oil and natural gas prices, future production of oil and natural gas reserves and future operating costs over the economic life of the property. In addition, other factors such as probable and possible reserves were taken into consideration when justified by economic conditions and the availability of capital to develop proved undeveloped reserves. For each property determined to be impaired, we recognized an impairment loss equal to the difference between the estimated fair value and the carrying value of the field.

Fair value was estimated to be the present value of expected future net cash flows. Any impairment charge incurred was recorded in accumulated depletion, depreciation and amortization to reduce the carrying value of the field. Each part of this
calculation was subject to a large degree of judgment, including the determination of the fields' estimated reserves, future cash
flows and fair value.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
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We had no impairment for the three or six months ended June 30, 2016.

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.

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 Exit 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 acquisitions and impairments of oil and natural gas properties, if any, and our asset retirement obligations.

As of June 30, 2017 and December 31, 2016, 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.

Depreciation and Depletion—Depreciation and depletion of producing oil and natural gas properties is calculated using the units-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs.

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.

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 2.

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 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 when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized using the entitlements method. 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, 2017 and December 31, 2016, the net liability for natural gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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 7.

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 6.

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 5.

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 8.

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. The fair value of each restricted stock award is measured using the closing price of our common stock on the day of the award.

New Accounting Pronouncements

On November 17, 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash. This ASU is intended to reduce diversity in the presentation of restricted cash and restricted cash equivalents in the statement of cash flows and requires that restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendments in this ASU should be applied using a retrospective transition method to each period presented. For public entities, the amendments are effective for annual periods beginning after December 15, 2017. We are currently evaluating the provisions of this ASU and plan to adopt this standard when required for public companies.

On March 30, 2016, the FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The amendments in this ASU are intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. Several aspects of the accounting for share-based payment award transactions are simplified, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. For public entities, the amendments are effective for annual periods beginning after December 15, 2016. We adopted this standard in 2017 and anticipate no material impact on our consolidated financial statements until the fourth quarter of 2017, when the initial vestings of restricted stock issued under our Management Incentive Plan occur.

On February 25, 2016, the FASB issued ASU 2016-02, Leases (Topic 842). 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 relates 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. We are currently evaluating the provisions of this ASU and assessing the impact it may have on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. ASU 2014-09 will supersede most of the existing revenue recognition requirements in US GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which it expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures that are sufficient to enable users to understand an entity’s nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net). This update provides clarifications in the assessment of principal versus agent considerations in the new revenue standard. In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow Scope Improvements and Practical Expedients. The update reduces the potential for diversity in practice at initial application of Topic 606 and the cost and complexity of applying Topic 606. In May 2016, the FASB issued ASU 2016-11, Revenue Recognition and Derivatives and Hedging: Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. This update rescinds certain SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities-Oil and Gas, effective upon adoption of Topic 606. These ASUs are effective for annual and interim periods beginning after December 15, 2017. The Company has not yet selected a transition method. The Company is currently analyzing the impact of Update 2014-09, and the related ASU's, to evaluate the impact of the new standard on its revenue contracts. The Company is considering its revenue contracts, reviewing for potential changes that may be needed to its accounting policies and evaluating the new disclosure requirements. The Company expects to complete its evaluations of the impacts of the accounting and disclosure requirements in the second half of 2017.

NOTE 2—Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the period ending June 30, 2017 is as follows (in thousands):

	June 30, 2017
Beginning balance at December 31, 2016	$2,933
Liabilities incurred	64
Accretion expense	112
Ending balance at June 30, 2017	$3,109

Current liability	$—
Long term liability	$3,109

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3—Debt

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

	June 30, 2017		December 31, 2016	
	Principal	Carrying Amount	Principal	Carrying Amount
Exit Credit Facility	$16,651	$16,651	$16,651	$16,651
13.50% Convertible Second Lien Senior Secured Notes due 2019 (1)	43,996	34,529	41,170	30,554
Total debt	$60,647	$51,180	$57,821	$47,205

(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 $4.0 million and $1.2 million of paid in-kind interest at June 30, 2017 and December 31, 2016, respectively. The carrying value includes $9.5 million and $10.6 million of unamortized debt discount at June 30, 2017 and December 31, 2016, 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).

	Successor		Predecessor		Successor		Predecessor	
	Three Months Ended June 30, 2017		Three Months Ended June 30, 2016		Six Months Ended June 30, 2017		Six Months Ended June 30, 2016	
	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate
Successor Exit Credit Facility	$279	6.6 %	$—	*	$531	6.3 %	$—	*
13.50% Convertible Second Lien Senior Secured Notes due 2019 (1)	2,081	24.3 %	—	*	4,008	24.3 %	—	*
Predecessor Senior Credit Facility	—	—	1,043	*	—	—	1,913	*
8.0% Second Lien Senior Secured Notes due 2018 **	—	—	(195)	*	—	—	913	*
8.875% Senior Notes due 2019	—	—	419	*	—	—	3,107	*
3.25% Convertible Senior Notes due 2026	—	—	1	*	—	—	4	*
5.0% Convertible Senior Notes due 2029	—	—	13	*	—	—	97	*
5.0% Convertible Senior Notes due 2032	—	—	329	*	—	—	2,382	*
5.0% Convertible Exchange Senior Notes due 2032	—	—	—	*	—	—	1,484	*
Other	—	—	16	*	—	—	39	*
Total debt	$2,360		$1,626		$4,539		$9,939	

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

* - Not comparative as the Company was in bankruptcy during portions of the 2016 periods shown and did not pay interest on its debt while in bankruptcy.

** - Includes $3.8 million gain from the change in fair value of the embedded derivative associated with the 8.0% Second Lien Notes.

Exit Credit Facility

On the Effective Date, upon consummation of the plan of reorganization, 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 (“the 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”), with available borrowing capacity of $20.0 million. As of June 30, 2017, we had $16.7 million outstanding on the Exit Credit Facility.

The maturity date of the Exit Credit Agreement is September 30, 2018, unless the Borrower notifies the Administrative Agent that it intends to extend the maturity date to September 30, 2019, subject to certain conditions and the payment of a fee.

Until such maturity date, the Loans (as defined in the Exit Credit Agreement) under the Exit Credit Agreement shall bear interest at a rate per annum equal to (i) the alternative base rate plus an applicable margin of 4.50% or (ii) adjusted LIBOR plus an applicable margin of 5.50%. As of June 30, 2017, the interest rate on the Exit Credit Facility was 6.66%.

The Borrower may elect, at its option, to prepay any borrowing outstanding under the Exit Credit Agreement without premium or penalty (except with respect to any break funding payments, which may be payable pursuant to the terms of the Exit Credit Agreement).

The Borrower may be required to make mandatory prepayments of the Loans under the Exit Credit Agreement if the total borrowings exceed the aggregate credit amounts, and if the Borrower is not in compliance with the Total Proved Asset Coverage Ratio (as defined in the Exit Credit Agreement) or the Secured Debt Asset Coverage Ratio (as defined in the Exit Credit Agreement).

Additionally, if the Borrower has outstanding borrowings and the Consolidated Cash Balance (as defined in the Exit Credit Agreement and the First Amendment and Consent to Exit Credit Agreement dated December 22, 2016) exceeds (i) the sum of $27.5 million plus $21.3 million, which is calculated as the Equity Issuance Net Proceeds from the December 19, 2016 private placement less $2.5 million, as of the close of business on the most recently ended business day on or before March 31, 2018 or (ii) $7.5 million as of the close of business on the most recently ended business day on or after April 1, 2018, the Borrower may also be required to make mandatory prepayments in an aggregate principal amount equal to such excess.

Furthermore, the Borrower is required to make certain mandatory prepayments within one business day of (i) the issuance of any Equity Interests (as defined in the Exit Credit Agreement) of the Company, (ii) the consummation of any sale or other disposition of Property (as defined in the Exit Credit Agreement) and (iii) the assignment, termination or unwinding of any Swap Agreements (as defined in the Exit Credit Agreement).

Amounts outstanding under the Exit Credit Agreement are guaranteed by the Company and secured by a security interest in substantially all of the assets of the Company and the Borrower.

The Exit Credit Agreement contains certain customary representations and warranties, including as to organization; powers; authority; enforceability; approvals; no conflicts; financial condition; no material adverse change; litigation; environmental matters; compliance with laws and agreements; no defaults; Investment Company Act; taxes; ERISA; disclosure; no material misstatements; insurance; restrictions on liens; subsidiaries; location of business and offices; properties; titles, etc.; maintenance of properties; gas imbalances, prepayments; marketing of production; swap agreements; use of loans; solvency; sanctions laws and regulations; foreign corrupt practices; money laundering laws; and embargoed persons.

The Exit Credit Agreement also contains certain affirmative and negative covenants, including delivery of financial statements; conduct of business; reserve reports; title information; collateral and guarantee requirements; indebtedness; liens; dividends and distributions; investments; sale or discount of receivables; mergers; sale of properties; termination of swap agreements; transactions with affiliates; negative pledges; dividend restrictions; gas imbalances; take-or-pay or other prepayments; and swap agreements.

The Exit Credit Agreement 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 1.5 to 1.0 initially, and increasing to 2.0 to 1.0 or after December 31, 2018, (ii) Secured Debt Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.35 to 1.00 for any test date on or before September 30, 2017 and 1.50 to 1.00 after September 30, 2017, in the case of clauses (i) and (ii), to be determined as of January 1 and July 1 each year and as of the date of any Material Acquisition (as defined in the Exit Credit Agreement) or Material Disposition (as defined in the Exit Credit Agreement), (iii) commencing with the fiscal quarter ending March 31, 2018, a ratio of Debt (as defined in the Exit Credit Agreement) as of the end of each fiscal quarter to EBITDAX for the twelve months ending on the last day of such fiscal quarter, not to exceed 4.00 to 1.00, (iv) limitations on Consolidated Cash Balance, (v) limitations on general and administrative expenses and (vi) minimum liquidity requirements.

The Exit Credit Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; voluntary and involuntary bankruptcy; judgments; and change of control.

As of June 30, 2017, we were in compliance with all covenants within the Exit Credit Agreement.

13.50% Convertible Second Lien Senior Secured Notes Due 2019

On the Effective Date, 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 into an amount of the Company’s common stock equal to 15% of the common stock of the reorganized Company on a fully diluted basis, subject to adjustments. At closing, the Purchasers were issued 10-year costless warrants for common stock equal to 20% of the new common stock of the reorganized Company on a fully diluted basis. 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 will mature on August 30, 2019, or such later date as set forth in the Convertible Second Lien Notes, but in no event later than 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) is in effect, interest on the Convertible Second Lien Notes must be paid in-kind.

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 1.35 to 1.00 for any test date on or before September 30, 2017 and 1.50 to 1.00 after September 30, 2017, to be determined as of January 1 and July 1 of each year, (ii) limitations on general and administrative expenses and (iii) 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. $9.5 million of debt discount remains to be amortized on the Convertible Second Lien Notes as of June 30, 2017.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
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As of June 30, 2017, we were in compliance with all covenants within the Indenture governing the Convertible Second Lien Notes.

NOTE 4—Equity

During the three months ended June 30, 2017, holders of the 10 year costless warrants attached to 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. As of June 30, 2017, 1,124,999 warrants remain to be exercised under the Convertible Second Lien Notes.

NOTE 5—Net Loss Per Common Share

Upon our emergence from bankruptcy on the Effective Date, as discussed in Note 1—"Description of Business and Significant Accounting Policies", the Predecessor Company's outstanding common stock and preferred stock were canceled, and new common stock and warrants were then issued.

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, 2017 and 2016. The following table sets forth information related to the computations of basic and diluted loss per share.

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(Amounts in thousands, except per share data)		(Amounts in thousands, except per share data)	
Basic and Diluted loss per share:				
Net loss applicable to common stock	$(1,214)	$(10,346)	$(6,939)	$(30,083)
Weighted average shares of common stock outstanding	9,670	77,892	9,381	76,251
Basic and Diluted loss per share (1) (2) (3) (4)	$(0.13)	$(0.13)	$(0.74)	$(0.39)
(1) Common shares issuable upon assumed conversion of convertible preferred stock or dividends paid were not presented as they would have been anti-dilutive.	—	16,597	—	16,597
(2) Common shares issuable upon assumed conversion of the 2026 Notes, 2029 Notes, 2032 Exchange Notes and 2032 Notes or interest paid were not presented as they would have been anti-dilutive.	—	5,910	—	5,910
(3) Common shares issuable upon assumed conversion of restricted stock and stock warrants in 2016 were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.	334	13,885	296	13,885
(4) Common shares issuable upon conversion of the 13.50% Convertible Second Lien Senior Secured Notes due 2019, associated warrants and unsecured claim holders were not included in the computation of diluted	4,389	—	4,389	—

loss per common share since their inclusion would have been anti-dilutive.

NOTE 6—Income Taxes

We recorded no income tax expense or benefit for the three and six months ended June 30, 2017. We recorded a valuation allowance at December 31, 2016, which resulted in no net deferred tax asset or liability appearing on our statement of financial position. We recorded this valuation allowance after an evaluation of all available evidence (including our recent history of net operating losses in 2016 and prior years) that led to a conclusion that based upon the more-likely-than-not standard of the accounting literature, our deferred tax assets were unrecoverable. 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, 2017.

As of June 30, 2017, we have no unrecognized tax benefits. There were no significant changes to the calculation since December 31, 2016.

NOTE 7—Commodity Derivative Activities

We use commodity and financial derivative contracts to manage fluctuations in commodity prices and interest rates. 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 we recognized on our oil and natural gas derivatives for the three and six months ended June 30, 2017 and 2016:

Oil and Natural Gas Derivatives (in thousands)	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016
Gain on commodity derivatives not designated as hedges, settled	$ 4	$ —	$ 147	$ —
Gain on commodity derivatives not designated as hedges, not settled	762	6	359	30
Total gain on commodity derivatives not designated as hedges	$ 766	$ 6	$ 506	$ 30

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 a fair value amount of $0.4 million had our counterparties as a group been unable to fulfill their obligations as of June 30, 2017.

As of June 30, 2017, the open positions on our outstanding commodity derivative contracts, all of which were natural gas contracts with BP, were as follows:

Contract Type	Daily Volume (MMBtu)	Total Volume (MMBtu)	Fixed Price	Fair Value at June 30, 2017 (In thousands)
Natural Gas Swaps				
2017	6,000	1,104,000	$ 3.20	$ 114
2018	20,000	7,300,000	$2.985 - $3.015	$ 88
Natural Gas Costless Collars				
2017	12,000	2,208,000	$3.00 - $3.60	$ 157

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, 2017 (in thousands). We measure the fair value of our commodity derivative contracts by

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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
Current Assets Commodity Derivatives	$ —	$ 22	$ —	$ 22
Non-current Assets Commodity Derivatives	—	337	—	337
Current Liabilities Commodity Derivatives	—	—	—	—
Non-current Liabilities Commodity Derivatives	—	—	—	—
Total	$ —	$ 359	$ —	$ 359

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, 2017 and December 31, 2016:

	June 30, 2017			December 31, 2016		
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 Commodity Derivatives - Prepaid Expenses and Other	$ 687	$ (665)	$ 22	$ —	$ —	$ —
Fair Value of Commodity Derivatives - Other Non-current Assets	358	(21)	337	—	—	—
Current Liabilities Commodity Derivatives	(665)	665	—	—	—	—
Non-current Liabilities Commodity Derivatives	(21)	21	—	—	—	—
Total	$ 359	$ —	$ 359	$ —	$ —	$ —

NOTE 8—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, 2017 and 2016 was approximately $0.5 million and $0.4 million, respectively, and total rent expense for the six months ended June 30, 2017 and 2016 was approximately $0.9 million and $0.8 million, respectively.

Defined Contribution Plan – We have a defined contribution plan ("DCP") that has a Company matching option to employees' contributions. Participation in the DCP is voluntary and all employees of the Company are eligible to participate. We suspended the Company's match in April 2016. We charged to expense plan contributions of zero and $0.1 million for the three months ended June 30, 2017 and 2016, respectively, and zero and $0.1 million for the six months ended June 30, 2017 and 2016, respectively.

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, risks and liability under federal, state and local environmental laws and regulations;
- the impact of restrictive covenants in our debt agreements;
- the creditworthiness of our financial counterparties and operation partners;
- failure to satisfy our short- or long-term liquidity needs, including our inability to generate sufficient cash flow from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs; and

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- 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, 2016.

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of 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 externally available sources of financing, such as bank debt, asset divestitures, issuance 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 hedging 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 commodity prices for oil and natural gas. Such pricing factors are largely beyond our control; however, we have historically employed commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Emergence from Bankruptcy

On April 15, 2016 (the "Petition Date"), we and our subsidiary Goodrich Petroleum Company, L.L.C. filed voluntary bankruptcy petitions seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the "Bankruptcy Court"), to pursue a Chapter 11 plan of reorganization (the "Chapter 11 Cases"). We filed a motion with the Bankruptcy Court seeking joint administration of the Chapter 11 Cases under the caption In re Goodrich Petroleum Corporation, et al. (Case No. 16-31975). Our joint plan of reorganization (the "Plan of Reorganization") was confirmed by the Bankruptcy Court on September 28, 2016, and we emerged from bankruptcy on October 12, 2016 (the "Effective Date").

Upon our emergence from bankruptcy, we adopted Fresh Start Accounting in accordance with the requirements of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification 852, "Reorganizations". This resulted in our becoming a new entity for financial reporting purposes. At that time, our assets and liabilities were recorded at their fair values as of the Effective Date. The effects of the Plan of Reorganization and our application of fresh start accounting are reflected in our consolidated financial statements as of December 31, 2016. The related adjustments were recorded in our consolidated statement of operations as reorganization items for the year to date period ending on the Effective Date.

The application of fresh start accounting and the effects of the implementation of our Plan of Reorganization resulted in our Consolidated Financial Statements on or after October 12, 2016 (the "Effective Date") not being comparable with the Consolidated Financial Statements prior to that date. Our financial results for periods following our application of fresh start accounting will be different from historical trends, and the differences may be material.

All references made to “Successor” or “Successor Company” relate to the Company on and subsequent to the Effective Date. References to the “Successor” in this quarterly report relate to the periods after the Effective Date, which includes the first two quarters of 2017. References to “Predecessor” or “Predecessor Company” in this quarterly report refer to the Company prior to the Effective Date, which includes the first two quarters of 2016.

On the Effective Date, to better reflect the true economics of our exploration and development of oil and natural gas reserves, we transitioned from the Successful Efforts Method of Accounting for oil and gas activities to the Full Cost Method.

Overview of Second Quarter 2017 Results

Second Quarter 2017 financial and operating results include:

- We completed and produced from two operated horizontally drilled Haynesville Shale Trend natural gas wells.
- We added approximately 3,000 net acres to our Haynesville Shale Trend acreage position.
- We increased our natural gas production by 105% over the second quarter of 2016.

Primary Operating Areas

Haynesville Shale Trend

Our development acreage in this trend is primarily centered in DeSoto and Caddo parishes, Louisiana and Angelina and Nacogdoches counties, Texas. We held approximately 50,000 gross (26,000 net) acres as of June 30, 2017 producing from and prospective for the Haynesville Shale Trend. During the second quarter of 2017, we entered into transactions that increased our net acreage and contiguous acreage position that will allow us to drill longer lateral wells. Our net production volumes from our Haynesville Shale Trend wells represented approximately 85% of our total equivalent production on a Mcfe basis for the second quarter of 2017. We completed five gross (1.5 net) wells in the second quarter of 2017. We plan to focus all our 2017 drilling efforts in the Haynesville Shale Trend.

Tuscaloosa Marine Shale Trend

We held approximately 108,000 gross (80,000 net) acres in the TMS as of June 30, 2017. We have 2 gross (1.7 net) TMS wells drilled and waiting on completion. Our net production volumes from our TMS wells represented approximately 15% of our total equivalent production on a Mcfe basis and approximately 100% of our total oil production for the second quarter of 2017. We did not conduct any capital workover operations on any wells in the TMS during the second quarter of 2017.

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

In addition to adopting Fresh Start Accounting, the Successor also adopted the Full Cost Method of Accounting as of the Effective Date. Prior to the Effective Date, the Predecessor used the Successful Efforts Method of Accounting. The results of operations of the Successor and the Predecessor are not generally comparable nor are they individually comparable with prior periods. We believe however, that production volumes, oil and natural gas revenues, lease operating expenses and production and other taxes are generally comparable and consequently, unless otherwise indicated, the tables and discussions below include such comparisons between the Predecessor and the Successor for these operational items. We believe this presentation gives the reader a better understanding of our operational results in 2017.

The Predecessor 2016 Period results of operations reflect the period from January 1, 2016 to June 30, 2016. The items that had the most material financial effect on our Net Loss of $30.1 million for the six months ended June 30, 2016 were the cost of our failed restructuring effort prior to filing for bankruptcy, interest expense and depletion, depreciation and amortization expense.

The Successor 2017 Period results of operations reflect the period from January 1, 2017 to June 30, 2017. 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.

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,			
	Successor	Predecessor			Successor	Predecessor		
(In thousands, except for price data)	2017	2016	Variance		2017	2016	Variance	
Revenues:								
Natural gas	$8,086	$ 1,336	$6,750	505 %	$13,387	$ 2,903	$10,484	361 %
Oil and condensate	4,029	5,081	(1,052)	(21)%	8,139	9,978	(1,839)	(18)%
Natural gas, oil and condensate	12,115	6,417	5,698	89 %	21,526	12,881	8,645	67 %
Net Production:								
Natural gas (MMcf)	2,795	1,365	1,430	105 %	4,628	2,936	1,692	58 %
Oil and condensate (MBbls)	84	115	(31)	(27)%	166	269	(103)	(38)%
Total (Mmcfe)	3,299	2,055	1,244	61 %	5,623	4,550	1,073	24 %
Average daily production (Mcfe/d)	36,253	22,582	13,671	61 %	31,066	25,000	6,066	24 %
Average realized sales price per unit:								
Natural gas (per Mcf)	$2.89	$ 0.98	$1.91	195 %	$2.89	$ 0.99	$1.90	192 %
Natural gas (per Mcf) including cash settled derivatives	$2.89	$ 0.98	$1.91	195 %	$2.92	$ 0.99	$1.93	195 %
Oil and condensate (per Bbl)	$47.96	$ 44.09	$3.87	9 %	$49.03	$ 37.08	$11.95	32 %
Average realized price (per Mcfe)	$3.67	$ 3.12	$0.55	18 %	$3.83	$ 2.83	$1.00	35 %

Natural gas, oil and condensate revenues increased by $5.7 million and by $8.6 million for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016. The increases were primarily driven by higher natural gas production and higher realized oil and natural gas prices. The increase in natural gas production volumes is attributed to two operated Haynesville Shale Trend wells completed in the second quarter of 2017 and the continued production of two non-operated Haynesville Shale Trend wells completed in late 2016. Beginning in August 2016, we elected to take our production in-kind and market the majority of our non-operated Haynesville Shale Trend natural gas volumes resulting in an improvement in the prices we received on such natural gas volumes. Natural gas realized prices for the three and six months ended June 30, 2016 included the netting of transportation and processing costs on such volumes that was discontinued upon taking our production in-kind. For the three and six months ended June 30, 2017, 67% and 62%, respectively, of our oil and natural gas revenue was attributable to natural gas sales compared to 21% and 23% for the three and six months ended June 30, 2016, respectively.

We are concentrating on increasing our natural gas production volumes through increased drilling in the Haynesville Shale Trend.

Operating Expenses

As described below, operating expenses increased $0.7 million and $2.6 million in the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016. The increase in operating expenses was primarily the result of $2.9 million of lease operating expense workover costs in 2017 and recognition of additional transportation expense in 2017 by virtue of taking our production in-kind in the Haynesville Shale Trend and paying related transportation costs for that production.

	Three Months Ended June 30,				Six Months Ended June 30,			
	Successor	Predecessor			Successor	Predecessor		
Operating Expenses (in thousands)	2017	2016	Variance		2017	2016	Variance	
Lease operating expenses	$2,950	$ 1,957	$993	51 %	$7,261	$ 4,293	$2,968	69 %
Production and other taxes	424	677	(253)	(37)%	1,083	1,416	(333)	(24)%
Operating Expenses per Mcfe								
Lease operating expenses	$0.89	$ 0.95	$(0.06)	(6)%	$1.29	$ 0.94	$0.35	37 %
Production and other taxes	0.13	0.33	(0.20)	(61)%	0.19	0.31	(0.12)	(39)%

Lease Operating Expense

Lease operating expense increased $1.0 million and $3.0 million during the three and six months ended June 30, 2017, respectively compared to the same periods in 2016. The increase is substantially attributed to an increase in workover expense in addition to increased costs due to increased production. We incurred $0.7 million and $2.9 million in workover cost for the three and six months ended June 30, 2017, respectively and only $0.3 million and $0.5 million for the three and six months ended June 30, 2016, respectively.

Production and Other Taxes

Production and other taxes includes severance and ad valorem taxes. Severance taxes for the three and six months ended June 30, 2017 were $0.5 million and $0.8 million, respectively. Ad valorem taxes for the three months ended June 30, 2017 was negligible as a result of the receipt of refunds. Ad valorem taxes for the six months ended June 30, 2017 was $0.3 million. During the three and six months ended June 30, 2016, production and other taxes included severance tax of $0.2 million and $0.5 million, respectively and ad valorem tax of $0.5 million and $0.9 million, respectively.

Severance taxes remained flat reflecting decreased oil production volumes directly offset by tax increases due to the expiration of the exemption on certain wells in Mississippi and Louisiana. 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 exemption is applicable until the earlier of (i) 30 months from the date of first sale of production or (ii) payout of the well. 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. The net revenues from our wells drilled in our TMS acreage in Southwestern Mississippi and Southeast Louisiana have been favorably impacted by these exemptions.

The decrease in ad valorem tax between periods reflects the reduction in the assessed values of our properties.

	Three Months Ended June 30,		Six Months Ended June 30,	
	Successor	Predecessor	Successor	Predecessor
Operating Expenses (in thousands):	2017	2016	2017	2016
Transportation and processing	$1,868	$ 448	$3,044	$ 879
Exploration	—	289	—	486
Depreciation, depletion and amortization	$3,083	2,541	$5,377	5,686
General and administrative	$3,772	3,720	$8,235	10,084
Operating Expenses per Mcfe				
Transportation and processing	$0.57	$ 0.22	$0.54	$ 0.19
Exploration	$—	$ 0.14	$—	$ 0.11
Depreciation, depletion and amortization	$0.93	$ 1.24	$0.96	$ 1.25
General and administrative	$1.14	$ 1.81	$1.46	$ 2.22

Transportation and Processing Expense

Transportation and processing expense for the three and six months ended June 30, 2017 includes $1.0 million and $2.0 million, respectively, of transportation fees incurred on natural gas volumes that we take in-kind and pay directly to the transporter on non-operated Haynesville Shale Trend natural gas volumes, effective with August 2016 production. Transportation and processing expense for the three and six months ended June 30, 2017 also includes approximately $0.1

million of gathering line amortization fee associated with the Company's Wurtsbaugh 25&24 No. 1 well, which is expected to be fully amortized by August 2017. The transportation and processing expense for the three and six months ended June 30, 2016 did not include these take in-kind transportation fees as gathering fees for that period were netted against the Company's realized natural gas price.

Exploration

The Successor Company adopted the Full Cost Method of accounting as of the Effective Date, resulting in Exploration Cost being capitalized to the full cost pool rather than expensed.

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

DD&A expense in the 2017 Successor Period is calculated on the Full Cost Method of Accounting adopted upon our emergence from bankruptcy based upon asset carrying values as of December 31, 2016.

DD&A expense in the 2016 Predecessor Period is calculated on the Successful Efforts Method of Accounting.

General and Administrative ("G&A") Expense

The Successor Company recorded $3.8 million and $8.2 million in G&A expense in the three and six months ended June 30, 2017, respectively, which includes 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 to be compensated in common stock and (iii) $0.1 million and $0.3 million, respectively, of office rent amortization.

The Predecessor Company recorded $3.7 million and $10.1 million in G&A expense in the three and six months ended June 30, 2016, respectively, which includes $1.1 million and $2.2 million of share based compensation, respectively.

Other Income (Expense)

Other income (expense) (in thousands):	Three Months Ended June 30, Successor 2017	Three Months Ended June 30, Predecessor 2016	Six Months Ended June 30, Successor 2017	Six Months Ended June 30, Predecessor 2016
Interest expense	$(2,360)	$(1,626)	$(4,539)	$(9,939)
Gain on commodity derivatives not designated as hedges	766	6	506	30
Average funded borrowings adjusted for debt discount and accretion	$50,488	$436,861	$49,490	$432,314
Average funded borrowings	$60,165	$439,054	$59,459	$436,325

Interest Expense

The Successor Company's interest expense for the three and six months ended June 30, 2017 reflects 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 includes the paid in-kind interest and amortization of debt discount.

The Predecessor Company's interest expense for the three and six months ended June 30, 2016 reflects interest payable in cash of $1.5 million and $7.9 million, respectively, and non-cash interest of $0.1 million and $2.0 million, respectively. The Predecessor Company did not record interest expense subsequent to the Petition Date on any of its outstanding second lien and senior notes. All the accrued interest on such notes was never paid as the underlying debt was canceled in bankruptcy.

Gain on Commodity Derivatives Not Designated as Hedges

Gain on commodity derivatives not designated as hedges for the three months ended June 30, 2017 is 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 is 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.
Restructuring

As a result of our efforts to restructure the Company outside of bankruptcy and the preliminary preparation involved in filing the Chapter 11 Cases during the first two quarters of 2016, we incurred significant professional fees and other costs. Restructuring costs incurred during the three and six months ending June 30, 2016 totaled $0.8 million and $5.1 million, respectively. No restructuring costs have been incurred during 2017.

Reorganization items, net

We anticipate that we will continue to incur professional fees and costs until the bankruptcy case is final. We continue to work on settling bankruptcy claims. We believe that the estimated liability we have established for these costs is sufficient to cover such cost.

Income Tax Benefit
We recorded no income tax expense or benefit for the three and six months ended June 30, 2017. We recorded a valuation allowance at December 31, 2016, which resulted in no net deferred tax asset or liability appearing on our statement of financial position. We recorded this valuation allowance after an evaluation of all available evidence (including our recent history of net operating losses in 2016 and prior years) that led to a conclusion that based upon the more-likely-than-not standard of the accounting literature, our deferred tax assets were unrecoverable. 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, 2017.

Adjusted EBITDA/EBITDAX

Adjusted EBITDA/EBITDAX 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 Predecessor defined Adjusted EBITDAX as earnings before interest expense, income tax, DD&A, exploration expense, share based compensation expense and impairment of oil and natural gas properties. The Successor calculates Adjusted EBITDA in the same way, but EBITDA reflects the absence of exploration expense in the Full Cost Method of Accounting used by the Successor. In calculating Adjusted EBITDA/EBITDAX, gains/losses on commodity derivatives not designated as hedges and net cash received or paid in settlement of derivative instruments are also excluded. Other excluded items include interest income, gain on sale of assets, restructuring, reorganization and other expense. Adjusted EBITDA/EBITDAX is not a measure of net income (loss) as determined by US GAAP. Adjusted EBITDA/EBITDAX 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/EBITDAX 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)	Successor	Predecessor	Successor	Predecessor
	2017	2016	2017	2016
Net loss (US GAAP)	$(1,214)	$ (5,229)	$(6,939)	$ (23,962)
Exploration expense	—	289	—	486
Interest expense	2,360	1,626	4,539	9,939
Depreciation, depletion and amortization	3,083	2,541	5,377	5,686
Share based compensation expense	1,651	1,101	3,379	2,171
Gain on commodity derivatives not designated as hedges	(766)	(6)	(506)	(30)
Net cash received in settlement of derivative instruments	4	—	147	—

Other items (1)	(12)	316	(216)	3,950
Adjusted EBITDA/EBITDAX	$5,106	$ 638	$5,781	$ (1,760)

(1) Other items include interest income, gain on sale of assets, restructuring, reorganization and other 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 may not be comparable to other similarly totaled measures of other companies.

Liquidity and Capital Resources

Overview

Our primary sources of cash during the first half of 2017 were cash on hand and cash from operating activities. We used cash primarily to fund capital expenditures. We currently plan to fund our operations and capital expenditures for the remainder of 2017 through a combination of cash on hand and cash from operating activities, although we may from time to time consider the funding alternatives described below.

We exited the second quarter of 2017 with cash of $35.0 million, which includes $0.6 million of restricted cash held as collateral for the issuance of a letter of credit in connection with a natural gas gathering agreement. As of June 30, 2017, we had outstanding debt under the Exit Credit Facility of $16.7 million, which matures at the earliest in September 2018 and $44.0 million Convertible Second Lien Notes outstanding, which matures at the earliest in August 2019.

Our total capital expenditure budget for 2017 is expected to range between $35 million to $45 million. We plan to focus all of our 2017 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:

- entering into a replacement bank credit facility;
- 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 45% of our natural gas sales volumes for the first half of 2017. We had no oil derivative contracts for the first half of 2017. For additional information on our derivative instruments see Note 7—“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,	
	Successor 2017	Predecessor 2016	Successor 2017	Predecessor 2016
Cash flow statement information:				
Net cash:				
Provided by (used in) operating activities	$10,863	$ (1,826)	$15,528	$(12,314)
Used in investing activities	(14,135)	(754)	(17,519)	(1,471)
(Used in) provided by financing activities	(266)	(28)	(448)	12,075
Decrease in cash and cash equivalents	$(3,538)	$ (2,608)	$(2,439)	$(1,710)

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, 2017. Changes in working capital also impact cash flows. 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, and 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.

Investing activities: We recorded capital expenditures of approximately $14.1 million and $20.4 million during the three and six months ended June 30, 2017, respectively. The full year 2017 capital expenditures include $1.5 million of capitalized internal costs directly related to our acquisition of leasehold, drilling and completion activities. Net cash used in investing activities was $17.5 million for the six months ended June 30, 2017, with the difference attributed to $2.5 million accrued at June 30, 2017, $0.6 million of utilized inventory, and the utilization of $0.4 million of cash advanced in 2016, offset by the $0.6 million accrued at December 31, 2016 and paid in 2017. Capital expenditures during the three months ended June 30, 2017 were substantially all spent on drilling and completions costs, while capital expenditures for the six months ended June 30, 2017 were comprised of $20.3 million associated with drilling and completions costs and $0.1 million for miscellaneous expenditures.

Financing activities: Net cash used in financing activities for the three and six months ended June 30, 2017 consisted of $0.3 million and $0.4 million, respectively, in registration and issuance costs associated with various securities issued since our emergence from bankruptcy or to be issued in the future.
Debt consisted of the following balances as of the dates indicated (in thousands):

	June 30, 2017		December 31, 2016	
	Principal	Carrying Amount	Principal	Carrying Amount
Exit Credit Facility	$16,651	$16,651	$16,651	$16,651
13.50% Convertible Second Lien Senior Secured Notes due 2019 (1)	43,996	34,529	41,170	30,554
Total debt	$60,647	$51,180	$57,821	$47,205

(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 $4.0 million and $1.2 million of paid in-kind interest at June 30, 2017 and December 31, 2016, respectively. The carrying value includes $9.5 million and $10.6 million of unamortized debt discount at June 30, 2017 and December 31, 2016, respectively.

For additional information on our financing activities, see Note 3—“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, 2016, 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, 2017.

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 3—“Debt” and Note 7—“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 entered into natural gas derivative instruments during the six months ended June 30, 2017 in order to reduce the price risk associated with production in 2017 of approximately 18,000 MMBtu per day. We did not enter into derivatives instruments for trading purposes. Utilizing actual derivative contractual volumes, a hypothetical 10% increase in underlying commodity prices would have decreased the derivative asset position, while a hypothetical 10% decrease in underlying commodity prices would have increased the derivative asset. The aforementioned decrease and increase in the net derivative liability position would have been de minimis to our consolidated financial statements as of June 30, 2017. Furthermore, a gain or loss would have been substantially offset by an increase or decrease, 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, 2016.

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, 2017, 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 1—“Description of Business and Significant Accounting Policies” and Note 8—“Commitments and Contingencies” to the Notes to Consolidated Financial Statements and Part I, Item II under “—Emergence from Bankruptcy” in this Quarterly Report on Form 10-Q.

As of June 30, 2017, we did not have any material outstanding and pending litigation.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2016, 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 the Goodrich Petroleum Corporation Management Incentive Plan effective December 8, 2016
10.2*	Second Amendment to the Goodrich Petroleum Corporation Management Incentive Plan effective May 23, 2017
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 4, 2017 By: /S/ Walter G. Goodrich
Walter G. Goodrich
Chairman & Chief Executive Officer

Date: August 4, 2017 By: /S/ Robert T. Barker
Robert T. Barker
Vice President, Controller, Chief Accounting Officer and Chief Financial Officer