

Titan Energy, LLC
Form 424B3
November 29, 2017
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Filed pursuant to Rule 424(b)(3)

Registration No. 333-214850

PROSPECTUS SUPPLEMENT NO. 3

(to Prospectus dated May 11, 2017)

Titan Energy, LLC

3,266,936 Common Shares

Representing Limited Liability Company Interests

This prospectus supplement is being filed to update and supplement information contained in the prospectus dated May 11, 2017 with information contained in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2017, filed with the Securities and Exchange Commission (the "SEC") on November 28, 2017.

This prospectus supplement updates and supplements the information in the prospectus and is not complete without, and may not be delivered or utilized except in combination with, the prospectus, including any other amendments or supplements thereto. This prospectus supplement should be read in conjunction with the prospectus and if there is any inconsistency between the information in the prospectus and this prospectus supplement, you should rely on the information in this prospectus supplement.

Investing in our Common Shares involves risks. Please read "Risk Factors" beginning on page 3 of the prospectus.

Neither the SEC nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus supplement is November 29, 2017

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

FORM 10-Q

(Mark One)

**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE
ACT OF 1934**

For the quarterly period ended September 30, 2017

OR

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE
ACT OF 1934**

For the transition period from _____ to _____

Commission file number: 001-35317

TITAN ENERGY, LLC

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

425 Houston Street, Suite 300

Fort Worth, TX
(Address of principal executive offices)

Registrant's telephone number, including area code: 800-251-0171

90-0812516
(I.R.S. Employer
Identification No.)

76102
(Zip code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See 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

Emerging growth company

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 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 number of outstanding common shares of the registrant on November 27, 2017 was 5,444,794.

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ON FORM 10-Q

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FORWARD-LOOKING STATEMENTS

The matters discussed within this report include forward-looking statements. These statements may be identified by the use of forward-looking terminology such as anticipate, believe, continue, could, estimate, expect, intend, may, might, plan, potential, predict, should, or will, or the negative thereof or other variations thereon or comparable terminology. In particular, statements about our expectations, beliefs, plans, objectives, assumptions or future events or performance contained in this report are forward-looking statements. We have based these forward-looking statements on our current expectations, assumptions, estimates and projections. While we believe these expectations, assumptions, estimates and projections are reasonable, such forward-looking statements are only predictions and involve known and unknown risks and uncertainties, many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. Some of the key factors that could cause actual results to differ from our expectations include:

our ability to achieve the anticipated benefits from the consummation of the filings by our predecessor under Chapter 11 of the United States Bankruptcy Code;

the prices of natural gas, oil, NGLs and condensate;

changes in the market price of our common shares;

future financial and operating results;

actions that we may take in connection with our liquidity needs, including the ability to service our debt and satisfy covenants in our debt documents, as well as the potential issuance of significant amounts of equity;

economic conditions and instability in the financial markets;

the impact of our securities being quoted on the OTCQX Market rather than listed on a national exchange like the NYSE;

success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves and meeting our substantial capital investment needs;

the accuracy of estimated natural gas and oil reserves;

the financial and accounting impact of hedging transactions;

potential changes in tax laws and environmental and other regulations which may affect our operations;

the ability to obtain adequate water to conduct drilling and production operations, and to dispose of the water used in and generated by these operations at a reasonable cost and within applicable environmental rules;

the effects of unexpected operational events and drilling conditions, and other risks associated with drilling operations;

impact fees and severance taxes;

the effects of intense competition in the natural gas and oil industry;

general market, labor and economic conditions and uncertainties;

the ability to retain certain key customers;

dependence on the gathering and transportation facilities of third parties;

the availability of drilling rigs, equipment and crews;

access to sufficient amounts of carbon dioxide for tertiary recovery operations;

expirations of undeveloped leasehold acreage;

exposure to financial and other liabilities of the managing general partners of the investment partnerships;

exposure to new and existing litigation; and

development of alternative energy resources.

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Other factors that could cause actual results to differ from those implied by the forward-looking statements in this report are more fully described under Item 1A: Risk Factors in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Table of Contents**PART I: FINANCIAL INFORMATION****ITEM 1: FINANCIAL STATEMENTS****TITAN ENERGY, LLC****CONDENSED CONSOLIDATED BALANCE SHEETS****(in thousands)****(Unaudited)**

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 21,581	\$ 24,446
Accounts receivable	25,200	26,472
Advances to affiliates		4,145
Subscriptions receivable		5,656
Prepaid expenses and other	12,519	17,108
Current assets held for sale (Note 3)		8,271
Total current assets	59,300	86,098
Property, plant and equipment, net	527,397	670,769
Other assets, net	3,628	10,562
Non-current advances to affiliates	15,100	
Non-current assets held for sale (Note 3)		114,405
Total assets	\$ 605,425	\$ 881,834
LIABILITIES AND MEMBERS EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	\$ 29,868	\$ 27,647
Liabilities associated with drilling contracts		10,656
Current portion of derivative liability	3,629	30,519
Accrued well drilling and completion costs	1,959	4,933
Accrued interest	789	1,503
Accrued liabilities	13,079	17,171
Advances from affiliates	1,800	
Current portion of long-term debt	538,085	694,810
Current liabilities held for sale (Note 3)		9,461
Total current liabilities	589,209	796,700
Long-term derivative liability	896	13,208
Asset retirement obligations	14,570	15,031

Other long-term liabilities	811	1,431
Non-current liabilities held for sale (Note 3)		62,405
Commitments and contingencies (Note 9)		
Members' Equity (Deficit):		
Series A Preferred member's equity (deficit)	(28)	(145)
Common shareholders' equity (deficit)	(33)	(6,796)
Total members' equity (deficit)	(61)	(6,941)
Total liabilities and members' equity (deficit)	\$ 605,425	\$ 881,834

See accompanying notes to condensed consolidated financial statements.

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TITAN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Successor			Predecessor	
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Period from January 1, 2016 through August 31, 2016
Revenues:					
Gas and oil production	\$ 47,424	\$ 160,930	\$ 17,261	\$ 36,290	\$ 129,077
Drilling partnership management	1,997	17,387	2,074	18,778	24,446
Gain (loss) on mark-to-market derivatives	(4,068)	36,925	(2,079)	2,353	(23,248)
Total revenues	45,353	215,242	17,256	57,421	130,275
Costs and expenses:					
Gas and oil production	21,633	74,355	9,854	18,577	80,988
Drilling partnership management	248	10,026	1,266	16,121	17,427
General and administrative	10,142	32,961	4,530	5,128	41,038
Depreciation, depletion and amortization	11,934	38,402	5,152	20,585	73,272
Loss on divestiture	5,177	43,369			
Total costs and expenses	49,134	199,113	20,802	60,411	212,725
Operating income (loss)	(3,781)	16,129	(3,546)	(2,990)	(82,450)
Interest expense	(15,268)	(41,816)	(3,470)	(14,087)	(71,059)
Gain (loss) on asset sales and disposal	(82)	25	5	(18)	(551)
Gain on early extinguishment of debt					26,498
Reorganization items, net			(353)	(16,614)	(16,614)
Other income (loss)	(777)	(925)		(3,063)	(3,063)
Loss before income taxes	(19,908)	(26,587)	(7,364)	(36,772)	(147,239)
Income tax provision (benefit)	(202)	(11,503)			
Net loss from continuing operations	(19,706)	(15,084)	(7,364)	(36,772)	(147,239)
Net income (loss) from discontinued operations	2,156	20,945	(167)	(11,852)	(30,191)
Net income (loss)	(17,550)	5,861	(7,531)	(48,624)	(177,430)

Preferred member / limited partner dividends						(4,013)
Net income (loss) attributable to common shareholders and preferred members	\$ (17,550)	\$ 5,861	\$ (7,531)	\$	\$	
Net income (loss) attributable to common limited partners and the general partner	\$	\$	\$	\$ (48,624)	\$ (181,443)	
Allocation of net income (loss) attributable to:						
Preferred member	\$ (351)	\$ 117	\$ (151)	\$	\$	
Net loss attributable to common shareholders	\$ (17,199)	\$ 5,744	\$ (7,380)	\$	\$	
Common limited partners' interest				(47,651)	(177,814)	
General partner's interest				(973)	(3,629)	
Net loss attributable to common shareholders per share / common limited partners per unit (Note 2):						
Basic and diluted loss continuing operations	\$ (3.71)	\$ (2.85)	\$ (1.40)	\$ (0.35)	\$ (1.44)	
Basic and diluted income (loss) discontinued operations	\$ 0.41	\$ 3.96	\$ (0.03)	\$ (0.11)	\$ (0.28)	
Weighted average shares / common limited partner units outstanding (Note 2):						
Basic and diluted	5,208	5,186	5,139	104,366	102,912	

See accompanying notes to condensed consolidated financial statements.

Table of Contents**TITAN ENERGY, LLC****CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)****(in thousands)****(Unaudited)**

	Successor			Predecessor	
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Period from January 1, 2016 through August 31, 2016
Net income (loss)	\$(17,550)	\$ 5,861	\$ (7,531)	\$(48,624)	\$ (177,430)
Other comprehensive loss:					
Derivative instruments designated as cash flow hedges:					
Reclassification to net income (loss) of mark-to-market gains				(1,461)	(10,387)
Reclassification adjustment for net reorganization gain included in net loss				(8,617)	(8,617)
Total other comprehensive loss				\$(10,078)	\$ (19,004)
Comprehensive income (loss) attributable to Series A Preferred member and common shareholders	\$(17,550)	\$ 5,861	\$ (7,531)	\$	\$
Comprehensive loss attributable to common and preferred limited partners and the general partner	\$	\$	\$	\$(58,702)	\$ (196,434)

See accompanying notes to condensed consolidated financial statements.

Table of Contents**TITAN ENERGY, LLC****CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN MEMBERS EQUITY (DEFICIT)****(in thousands, except unit data)****(Unaudited)**

	Series A Preferred Members Interest		Common Shareholders Interest		Total Members Equity (Deficit)
	Shares	Amount	Shares	Amount	
Balance at December 31, 2016	1	\$ (145)	5,447,787	\$ (6,796)	\$ (6,941)
Net issued and unissued shares under incentive plans			(20,240)	1,019	1,019
Net income		117		5,744	5,861
Balance at September 30, 2017	1	\$ (28)	5,427,547	\$ (33)	\$ (61)

See accompanying notes to condensed consolidated financial statements.

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TITAN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Successor Period from September 1, Nine Months 2016 through Ended September 30, 2017	2016	Predecessor Period from January 1, 2016 through August 31, 2016
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	\$ 5,861	\$ (7,531)	\$ (177,430)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Net (income) loss from discontinued operations	(20,945)	167	30,191
Depreciation, depletion and amortization	38,402	5,152	73,272
Loss on divestiture	43,369		
Non-cash reorganization items			(10,312)
(Gain) loss on derivatives	(16,516)	2,036	13,804
(Gain) loss on asset sales and disposal	347	(5)	551
Gain on extinguishment of debt			(26,498)
Other (income) loss	1,890		3,063
Non-cash compensation expense	1,019	68	1,167
Non-cash interest expense	22,500	2,034	
Valuation allowance on deferred tax asset	(11,025)		1,596
Amortization of deferred financing costs and discount and premium on long-term debt	1,849	125	12,361
Changes in operating assets and liabilities:			
Monetization of derivatives			214,375
Accounts receivable, prepaid expenses and other	(31,142)	5,954	99,284
Accounts payable and accrued liabilities	(12,602)	(2,856)	(39,914)
Net cash provided by continuing operating activities	23,007	5,144	195,510
Net cash provided by discontinued operating activities	5,868	4,254	25,596
Net cash provided by operating activities	28,875	9,398	221,106
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(37,239)	(5,367)	(24,894)
Net proceeds from sale of assets	109,073		

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Net cash provided by (used in) continuing investing activities	71,834	(5,367)	(24,894)
Net cash provided by discontinued investing activities	76,953		
Net cash provided by (used in) investing activities	148,787	(5,367)	(24,894)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under revolving credit facility			135,000
Repayments under revolving credit facility	(179,536)		(291,191)
Senior note repurchases			(5,528)
Distributions paid to shareholders/unitholders			(12,578)
Net proceeds from issuance of common limited partner units			204
Deferred financing costs, distribution equivalent rights and other	(991)	(150)	(8,044)
Net cash used in financing activities	(180,527)	(150)	(182,137)
Net change in cash and cash equivalents	(2,865)	3,881	14,075
Cash and cash equivalents, beginning of period	24,446	15,428	1,353
Cash and cash equivalents, end of period	\$ 21,581	\$ 19,309	\$ 15,428

See accompanying notes to condensed consolidated financial statements.

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TITAN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

NOTE 1 ORGANIZATION

We are a publicly traded (OTCQX: TTEN) Delaware limited liability company and an independent developer and producer of natural gas, crude oil and NGLs with operations in basins across the United States but primarily focused on the horizontal development of resource potential from the Eagle Ford Shale in South Texas. As discussed further below, we are the successor to the business and operations of Atlas Resource Partners, L.P. (ARP). Unless the context otherwise requires, references to Titan Energy, LLC, Titan, the Company, we, us, and our, refer to Titan Energy and our consolidated subsidiaries (and our predecessor, where applicable).

Titan Energy Management, LLC (Titan Management) manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of Atlas Energy Group, LLC (ATLS ; OTCQX: ATLS), which is a publicly traded company.

In addition to its preferred member interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (AGP), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

At September 30, 2017, we had 5,427,547 common shares representing limited liability company interests issued and outstanding.

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the Restructuring Support Agreement) with certain of their lenders (the Restructuring Support Parties) to support ARP's restructuring pursuant to a pre-packaged plan of reorganization (the Plan).

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 in the United States Bankruptcy Court for the Southern District of New York (the Bankruptcy Court, and the cases commenced thereby, the Chapter 11 Filings). The cases commenced thereby were jointly administered under the caption In re: ATLAS RESOURCE PARTNERS, L.P., et al.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the Plan Effective Date), pursuant to the Plan, the following occurred:

ARP's first lien lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than \$440 million of principal and face amount of letters of credit)

and became lenders under our first lien exit facility credit agreement, composed of a \$410 million conforming reserve-based tranche and a \$30 million non-conforming tranche (the First Lien Credit Facility) (refer to Note 5 Debt for further information regarding terms and provisions).

ARP s second lien lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of \$252.5 million (the Second Lien Credit Facility) (refer to Note 5 Debt for further information regarding terms and provisions). In addition, ARP s second lien lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.

ARP s senior note holders, in exchange for 100% of the \$668 million aggregate principal amount of senior notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

All of ARP s preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

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ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended.

Titan Management, a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. Four of the seven initial members of the board of directors were designated by Titan Management (the Titan Class A Directors). For so long as Titan Management holds such preferred share, the Titan Class A Directors will be appointed by a majority of the Titan Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

NOTE 2 BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES*Basis of Presentation*

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and the applicable rules and regulations of the Securities and Exchange Commission regarding interim financial reporting and include all adjustments that are necessary for a fair presentation of our consolidated results of operations, financial condition and cash flows for the periods shown, including normal, recurring accruals and other items. The consolidated results of operations for the interim periods presented are not necessarily indicative of results for the full year. The year-end condensed consolidated balance sheet was derived from audited financial statements but does not include all disclosures required by U.S. GAAP. For a more complete discussion of our accounting policies and certain other information, refer to our consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

In connection with the Chapter 11 Filings, we were subject to the provisions of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 852 *Reorganizations* (ASC 852).

Upon emergence from bankruptcy on the Plan Effective Date, we adopted fresh-start accounting in accordance with ASC 852. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Plan Effective Date, which differed materially from the recorded values of ARP's assets and liabilities.

As a result, our condensed consolidated statement of operations subsequent to the Plan Effective Date is not comparable to ARP's condensed consolidated statement of operations prior to the Plan Effective Date. Our condensed consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented on or after the Plan 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.

References to Successor relate to the Company on and subsequent to the Plan Effective Date. References to Predecessor refer to the Company prior to the Plan Effective Date. The condensed consolidated financial statements of

the Successor have been prepared assuming that the Company will continue as a going concern and contemplate the realization of assets and the satisfaction of liabilities in the normal course of business.

Reclassifications

Certain reclassifications have been made to our condensed consolidated financial statements for the prior year periods to conform to classifications used in the current year, specifically related to our discontinued operations (see Note 3) and our segment information on the condensed consolidated statement of operations and segment footnote disclosures (see Note 11).

Principles of Consolidation

Our condensed consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. Transactions between us and other ATLS managed operations have been identified in the condensed consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

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We sponsored and continue to manage tax-advantaged investment partnerships (the "Drilling Partnerships"), in which we coinvested, to finance a portion of our natural gas, crude oil and NGL production activities. In accordance with established practice in the oil and gas industry, our condensed consolidated financial statements include our pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the Drilling Partnerships in which we have an interest. Such interests generally approximate 10-30%. Our condensed consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, we calculate these items specific to our own economics.

Liquidity and Capital Resources and Ability to Continue as a Going Concern

Since the Plan Effective Date, we have funded our operations through cash flows generated from our operations and cash on hand. We currently do not have the capacity to access additional liquidity from our First Lien Credit Facility and our ability to access public equity and debt markets may be limited. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and continue to remain low in 2017. These lower commodity prices have negatively impacted our revenues, earnings and cash flows, which has negatively impacted our ability to remain in compliance with the covenants under our credit facilities. Sustained low commodity prices could have a material and adverse effect on our liquidity position.

Even following the amendments described below, we continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. If we are not able to enter into further amendments with our lenders prior to the expiration of the standstill period, we may be forced to seek further options as described below.

We were not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. As a result of the amendment referenced below, our financial covenants will not be tested again until the quarter ending December 31, 2017. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. We have classified \$538.1 million of outstanding indebtedness under our credit facilities, which is net of \$1.7 million of deferred financing costs, as current portion of long term debt, net within our condensed consolidated balance sheet as of September 30, 2017, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit.

On April 19, 2017, we entered into an amendment to our First Lien Credit Facility (which has been superseded by subsequent amendments as described further below). This amendment provided for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base (refer to Note 5 - Debt for further information regarding the specific amended terms and provisions). As part of our overall business strategy, we have continued to execute on our sales of non-core assets, which has included the sale of our Appalachia and Rangely operations. The proceeds of the consummated asset sales were used to repay borrowings under our First Lien Credit Facility. Our strategy is to continue to sell non-core assets to reduce our leverage position, which will also help us to comply with the requirements of our First Lien Credit Facility amendments.

In addition to the amendments to the financial ratio covenants, the First Lien Credit Facility lenders waived certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a going concern qualification. The First Lien Credit Facility lenders' waivers were subject to revocation in certain

circumstances, including the exercise of remedies by junior lenders (including pursuant to our Second Lien Credit Facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Credit Facility.

On April 21, 2017, the lenders under the our Second Lien Credit Facility delivered a notice of events of default and reservation of rights, pursuant to which they noticed events of default related to financial covenants and the failure to deliver financial statements without a going concern qualification. The delivery of such notice began the 180-day standstill period under the intercreditor agreement, during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility. The lenders have not accelerated the payment of amounts outstanding under the Second Lien Credit Facility.

On May 4, 2017, we entered into a definitive agreement to sell our conventional Appalachia and Marcellus assets to Diversified Gas & Oil, PLC (Diversified) for \$84.2 million. The transaction included the sale of approximately 8,400 oil and gas wells across Pennsylvania, Ohio, Tennessee, New York and West Virginia, along with the associated infrastructure (the Appalachian Assets). We retained our Utica Shale position, Indiana assets and West Virginia CBM assets in the region. On June 30, 2017, we completed a majority of the Appalachian Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility.

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On June 12, 2017, we entered into a definitive agreement to sell our 25% interest in Rangely Field to an affiliate of Merit Energy Company, LLC for \$105 million. Rangely is a CO₂ flood located in Rio Blanco County, Colorado, and operated by Chevron. The transaction includes the sale of our interest in Rangely Field, its 22% interest in Raven Ridge Pipeline, a CO₂ transportation line, as well as surrounding acreage in Rio Blanco and Moffat Counties, Colorado (collectively, the Rangely Assets). On August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility and achieve compliance with the requirement to reduce our First Lien Credit Facility borrowings below \$360 million, as required by August 31, 2017.

On September 27, 2017, the lenders under our Second Lien Credit Facility entered into a letter agreement with us and the lenders under our First Lien Credit Facility (the Extension Letter) (which has been superseded by subsequent amendments as described further below). Pursuant to the Extension Letter, the Second Lien Credit Facility lenders agreed to extend the 180-day standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing the Company's obligations under the Second Lien Credit Facility) by an additional 35 days from October 18, 2017 to November 22, 2017. In addition, the extension of the standstill period extends the waiver of certain defaults under the First Lien Credit Facility, which terminates 15 business days prior to the expiration of the standstill period. The parties agreed to extend the standstill period to provide the Company with additional time to negotiate proposed amendments to each of the First Lien Credit Facility and the Second Lien Credit Facility.

On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

On November 6, 2017, we entered into a fourth amendment to our First Lien Credit Facility. The fourth amendment has an effective date of October 31, 2017 and confirms the conforming and non-conforming tranches of the borrowing base at \$228.7 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$190 million by December 8, 2017 and to \$150 million by August 31, 2018. The maturity date of the non-conforming tranche of the borrowing base was confirmed as May 1, 2018. We are required to use proceeds from asset sales to make prepayments.

In addition to the requirements above, the First Lien Credit Facility lenders also agreed to a limited waiver of certain existing defaults with respect to financial covenants, required repayments of borrowings and other related matters. The waiver terminates upon the earliest of (i) December 8, 2017, (ii) the occurrence of additional events of default under the First Lien Credit Facility and (iii) the exercise of remedies under our Second Lien Credit Facility. Pursuant to the fourth amendment, we are required to hedge at least 50% and 80% of our 2019 projected proved developed producing production by December 31, 2017 and March 31, 2018, respectively.

In connection with, and as a condition to, the effectiveness of the fourth amendment to our First Lien Credit Facility, the lenders under our Second Lien Credit Facility agreed to extend the standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility are prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility) until December 29, 2017.

We continually review and may make changes to our capital structure from time to time, with the goal of strengthening our balance sheet and meeting our debt service obligations. We could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options, but there is no certainty that we will be able to implement any such options, and we cannot provide any

assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders.

We cannot assure you that we will be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that will be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions will allow us to meet our debt obligations and capital requirements.

Table of Contents*Use of Estimates*

The preparation of our condensed consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our condensed consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. Our condensed consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion of gas and oil properties, fair value of derivative instruments, and the fair value of assets held for sale. The oil and gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Actual results could differ from those estimates.

Assets Held For Sale

Assets are classified as held for sale when we commit to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. Any subsequent changes to the fair value less estimated costs to sell impact the measurement of assets held for sale, with any gain or loss reflected in the loss on divestitures line item in our condensed consolidated statements of operations. See Note 3 for additional disclosures regarding assets held for sale.

Discontinued Operations

A disposal of a component of our entity is classified as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on our operations and financial results. For components classified as discontinued operations, the balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities held for sale on the condensed consolidated balance sheet and to net income (loss) from discontinued operations on the condensed consolidated statement of operations for all periods presented. The gains or losses associated with these divested components are recorded in net income (loss) from discontinued operations on the condensed consolidated statement of operations. See Note 3 for additional disclosures regarding discontinued operations.

Predecessor's Reorganization Items, Net

Incremental costs incurred as a result of the Chapter 11 Filings, net gain on settlement of liabilities subject to compromise and reorganization adjustments, and net impact of fresh start adjustments are classified as Reorganization items, net in the Predecessor's condensed consolidated statement of operations. The following table summarizes the reorganization items:

Professional fees and other	\$ (33,065)
Accelerated amortization of deferred financing costs	(9,565)
Net gain on reorganization adjustments	361,479
Net loss on fresh start adjustments	(335,463)
Total reorganization items, net	\$ (16,614)

Income Taxes

Our effective tax rates for the Successor three and nine months ended September 30, 2017 were 1.27% and 0.74%, respectively, which represent our expected Texas Franchise Tax liability. Our income tax provision differs from the provision computed by applying the U.S. Federal statutory corporate income tax rate of 35% primarily due to the valuation allowance on our deferred tax assets. For the Successor three and nine months ended September 30, 2017, we recognized a provision for income taxes of \$0.2 million and \$11.5 million, respectively, in net income (loss) from discontinued operations on our condensed consolidated statement of operations. For the Successor three and nine months ended September 30, 2017, we recognized a corresponding income tax benefit of \$0.2 million and \$11.5 million, respectively, in net income (loss) from continuing operations on our condensed consolidated statement of operations, which represents a direct offset of the provision for income taxes included within our discontinued operations.

Successor s Management Incentive Plan

Pursuant to the Titan Energy, LLC Management Incentive Plan (the MIP) plan, participants are allowed to withhold or surrender shares for the payment of taxes. These shares are available for re-issuance under the MIP. For the three months ended September 30, 2017, 91,710 shares under the MIP became unrestricted. Of these shares, 42,251 were withheld for taxes, which resulted in \$0.2 million recognized in our consolidated statement of changes in members equity. For the nine months ended

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September 30, 2017, 91,710 shares under the MIP became unrestricted and 37,324 shares were granted and vested immediately. Of these shares, 57,562 were withheld for taxes, which resulted in \$0.3 million recognized in our consolidated statement of changes in members' equity. For the Successor period September 1, 2016 through September 30, 2016, 138,750 shares were granted and vested immediately.

Predecessor's 2012 Long-Term Incentive Plan

On May 12, 2016, due to the income tax ramifications of the potential options our Predecessor was considering, our Predecessor's Board of Directors delayed the vesting date of approximately 110,000 units granted to employees, directors and officers until March 2017. The phantom units were set to vest between May 15, 2016 and August 31, 2016. The delayed vesting schedule did not have a significant impact on the compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the Predecessor period from January 1, 2016 through August 31, 2016 or our Predecessor's remaining unrecognized compensation expense related to such awards. As a result of the Chapter 11 Filings, our Predecessor's 2012 LTIP phantom units were cancelled. The remaining unrecognized compensation cost of \$0.8 million was recognized upon the cancellation and was recorded in general and administrative expenses on the condensed consolidated statement of operations for the Predecessor period from July 1, 2016 through August 31, 2016.

Successor's Net Income Attributable to Common Shareholders Per Share

The Successor's basic net income attributable to common shareholders per share is computed by dividing net income attributable to our common shareholders by the weighted-average number of common shares outstanding, excluding any unvested restricted shares, for the period. The Successor's diluted net income attributable to common shareholders per share is similarly calculated except that the common shares outstanding for the period are increased using the treasury stock method to reflect the potential dilution that could occur if outstanding share based awards were vested at the end of the applicable period. Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted net income attributable to common shareholders per share as their impact would be anti-dilutive. We determine if potentially dilutive shares are anti-dilutive based on their impact to net income (loss) from continuing operations.

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The following is a reconciliation of net income attributable to our Successor's common shareholders for purposes of calculating net income attributable to our Successor's common shareholders per share (in thousands):

	Successor		
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016
Net loss from continuing operations	\$ (19,706)	\$ (15,084)	\$ (7,364)
Less: Series A Preferred member interest in loss from continuing operations	(394)	(302)	(147)
Net loss from continuing operations utilized in the calculation of net loss attributable to common shareholders per share	\$ (19,312)	\$ (14,782)	\$ (7,217)
Net income (loss) from discontinued operations	\$ 2,156	\$ 20,945	\$ (167)
Less: Series A Preferred member interest in net income (loss) from discontinued operations	43	419	(4)
Net income (loss) from discontinued operations utilized in the calculation of net income (loss) attributable to common shareholders per share	\$ 2,113	\$ 20,526	\$ (163)

The following table is a reconciliation of the Successor's basic and diluted weighted average number of common shares used to calculate basic and diluted net income attributable to common shareholders per share (in thousands):

	Successor		
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016
Weighted average number of common shares - basic ⁽¹⁾	5,208	5,186	5,139
Add dilutive effect of share based awards at end of period ⁽²⁾			
Weighted average number of common shares - diluted	5,208	5,186	5,139

- (1) For the three and nine months ended September 30, 2017, 186,000 and 278,000 restricted common shares outstanding, respectively, were excluded from the calculation of basic weighted average number of common shares because they were not vested. For the Successor period from September 1, 2016 through September 30, 2016, 278,000 restricted common shares outstanding were excluded from the calculation of basic weighted average number of common shares because they were not vested.
- (2) We determine if potentially dilutive shares are anti-dilutive based on their impact to net income (loss) from continuing operations. Since all of the periods presented resulted in net loss from continuing operations attributable to common shareholders, potentially dilutive shares were excluded because their inclusion would have been anti-dilutive.

Table of Contents*Predecessor's Net Income (Loss) Per Common Unit*

The following is a reconciliation of net income (loss) allocated to our Predecessor's common limited partners for purposes of calculating net income (loss) attributable to our Predecessor's common limited partners per unit (in thousands):

	Predecessor	
	Period From July 1 through August 31, 2016	Period From January 1 through August 31, 2016
Net loss from continuing operations	\$ (36,772)	\$ (147,239)
Preferred limited partner dividends		(4,013)
Net loss from continuing operations attributable to common limited partners and the general partner	(36,772)	(151,252)
Less: General partner's interest in net loss from continuing operations	(736)	(3,025)
Net loss from continuing operations attributable to common limited partners	(36,036)	(148,227)
Less: Net income from continuing operations attributable to participating securities phantom units		
Net loss from continuing operations utilized in the calculation of net loss attributable to common limited partners per unit Basic	(36,036)	(148,227)
Plus: Convertible preferred limited partner dividends ⁽¹⁾		
Net loss from continuing operations utilized in the calculation of net loss attributable to common limited partners per unit Diluted	\$ (36,036)	\$ (148,227)
Net loss from discontinued operations attributable to common limited partners and the general partner	\$ (11,852)	\$ (30,191)
Less: General partner's interest in net loss from discontinued operations	(237)	(604)
Net loss from discontinued operations attributable to common limited partners	(11,615)	(29,587)
Less: Net income from discontinued operations attributable to participating securities phantom units		
Net loss from discontinued operations utilized in the calculation of net loss attributable to common limited	(11,615)	(29,587)

partners per unit Basic

Plus: Convertible preferred limited partner dividends⁽¹⁾

Net loss from discontinued operations utilized in the
calculation of net loss attributable to common limited

partners per unit Diluted

\$ (11,615)

\$ (29,587)

- (1) For the periods presented, distributions on our Predecessor's Class C convertible preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

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The following table sets forth the reconciliation of our Predecessor's weighted average number of common limited partner units used to compute basic net income (loss) attributable to our Predecessor's common limited partners per unit with those used to compute diluted net income attributable to our Predecessor's common limited partners per unit (in thousands):

	Predecessor	
	Period From July 1 through August 31, 2016	Period From January 1 through August 31, 2016
Weighted average number of common limited partner units - basic	104,366	102,912
Add effect of dilutive incentive awards ⁽¹⁾		
Add effect of dilutive convertible preferred limited partner units ⁽²⁾		
Weighted average number of common limited partner units - diluted	104,366	102,912

- (1) For the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016, 247,000 and 274,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.
- (2) For the periods presented, potential common limited partner units issuable upon (a) conversion of our Predecessor's Class C preferred units and (b) exercise of the common unit warrants issued with our Predecessor's Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As our Predecessor's Class D and Class E preferred units were convertible only upon a change of control event, they were not considered dilutive securities for earnings per unit purposes.

Recently Issued Accounting Standards

In February 2016, the FASB updated the accounting guidance related to leases. The updated accounting guidance requires lessees to recognize a lease asset and liability at the commencement date of all leases (with the exception of short-term leases), initially measured at the present value of the lease payments. The updated guidance is effective for us as of January 1, 2019 and requires a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest period presented. We are currently in the process of determining the impact that the updated accounting guidance will have on our condensed consolidated financial statements.

In May 2014, the FASB updated the accounting guidance related to revenue recognition. The updated accounting guidance provides a single, contract-based revenue recognition model to help improve financial reporting by providing clearer guidance on when an entity should recognize revenue, and by reducing the number of standards to which an entity has to refer. In July 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. We have made progress on our contract reviews and

documentation. Substantially all of our revenue is earned pursuant to agreements under which we have currently interpreted one performance obligation, which is satisfied at a point-in-time. We are currently unable to reasonably estimate the expected financial statement impact; however, we do not believe the new accounting guidance will have a material impact on our financial position, results of operations or cash flows. We intend to adopt the new accounting guidance using the modified retrospective method. The new accounting guidance will require that our revenue recognition policy disclosures include further detail regarding our performance obligations as to the nature, amount, timing, and estimates of revenue and cash flows generated from our contracts with customers.

NOTE 3 DISCONTINUED OPERATIONS AND DIVESTITURES

Appalachia Divestiture Discontinued Operations

As disclosed in Note 2, on June 30, 2017, we completed a majority of the Appalachian Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility. On September 29, 2017, we completed the remainder of the Appalachian Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

We determined the Appalachian Assets represent discontinued operations as they constitute a disposal of a group of components and a strategic shift that will have a major effect on our operations and financial results. We evaluated the Appalachian Assets sale on our gas and oil production and Drilling Partnership management segments results of operations and cash flows, as well as expected

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asset retirement obligations, and concluded the impact will have a major effect on our expected operations and financial results. As a result, we reclassified the Appalachian Assets from their historical presentation to assets and liabilities held for sale on the condensed consolidated balance sheet and to net income (loss) from discontinued operations on the condensed consolidated statement of operations for all periods presented.

We determined that the carrying value of the remainder of our Appalachian Assets exceeded the fair value less costs to sell, which resulted in an impairment of \$4.3 million recognized in net income (loss) from discontinued operations on our condensed consolidated statement of operations during the nine months ended September 30, 2017.

The following table reconciles the major classes of line items from the discontinued operations of the Appalachian Assets included within net income (loss) from discontinued operations, in thousands:

	Successor			Predecessor	
	Three Months	Nine Months	Period From	Period From	Period
	Ended	Ended	September 1	July 1 to	From
	September 30,	September 30,	to	August 31,	January 1 to
	2017	2017	September 30,	2016	August 31,
	2017	2017	2016	2016	2016
Revenues:					
Gas and oil production	\$ 288	\$ 21,213	\$ 1,197	\$ 2,917	\$ 10,037
Drilling partnership management		5,114	1,320	3,621	12,100
Gain (loss) on mark-to-market derivatives		4,955	750	875	(667)
Total revenues	288	31,282	3,267	7,413	21,470
Costs and expenses:					
Gas and oil production	\$ 924	\$ 9,091	\$ 760	\$ 1,454	\$ 6,244
Drilling partnership management	597	5,824	1,074	2,312	9,801
Depreciation, depletion and amortization		4,842	869	2,693	9,059
General and administrative	298	4,378	395	12,044	16,974
Gain on sale of assets	(4,319)	(32,921)	(4)	(50)	(72)
Impairment on assets held for sale		4,272			
Interest expense	115	2,769	340	842	3,529
Other (income) loss	541	541		(30)	6,126
Total costs and expenses	\$ (1,844)	\$ (1,204)	\$ 3,434	\$ 19,265	\$ 51,661
Income (loss) from discontinued operations before income taxes	2,132	32,486	(167)	(11,852)	(30,191)
Income tax provision (benefit)	(24)	11,541			
Net income (loss) from discontinued operations	\$ 2,156	\$ 20,945	\$ (167)	\$ (11,852)	\$ (30,191)

We allocated First Lien Credit Facility interest expense to our discontinued operations based on the relative proportion of the net cash proceeds from the sale of the Appalachian Assets used to repay outstanding indebtedness under our

First Lien Credit Facility to the total outstanding indebtedness under our First Lien Credit Facility for the periods presented.

We allocated gain (loss) on mark-to-market natural gas commodity derivatives to our discontinued operations based on the relative proportion of the Appalachian Assets' natural gas production volumes to our total natural gas production volumes for the periods presented.

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The following table details the major classes of assets and liabilities of the Appalachian Assets discontinued operations classified as held for sale for the prior period presented, in thousands:

	December 31, 2016
Current assets:	
Accounts receivable	\$ 7,254
Prepaid expenses and other	1,017
Total current assets	8,271
Property, plant and equipment, net	113,956
Other assets	449
Total non-current assets	114,405
Total assets classified as held for sale	\$ 122,676
Current liabilities:	
Accounts payable	\$ 2,516
Current portion of derivative liability	4,279
Accrued liabilities and other	2,666
Total current liabilities	9,461
Long-term derivative liability	1,407
Asset retirement obligations	60,316
Other long-term liabilities	682
Total non-current liabilities	62,405
Total liabilities classified as held for sale	\$ 71,866

We allocated natural gas commodity derivatives assets and liabilities to our discontinued operations held for sale based on the relative proportion of the Appalachian Assets natural gas production volumes to our total natural gas production volumes as of December 31, 2016.

Rangely Divestiture

As disclosed in Note 2, on August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility. We determined that the carrying value of the Rangely Assets exceeded the fair value less costs to sell, which resulted in an impairment of \$38.2 million recognized in loss on divestiture on our condensed consolidated statement of operations during the Successor nine months ended September 30, 2017. We recognized a \$5.2 million loss on asset sale from the closing of the Rangely Assets sale during the Successor three and nine months ended September 30, 2017 resulting from final negotiations

and settlement of working capital adjustments in connection with the preliminary purchase price adjustments.

We considered the Rangely Assets to be an individually significant component of our operations. The following table presents the net income (loss) before income taxes of the Rangely Assets for the periods presented, in thousands:

	Successor			Predecessor	
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period From September 1 to September 30, 2016	Period From July 1 to August 31, 2016	Period From January 1 to August 31, 2016
Income (loss) before income taxes ⁽¹⁾	\$ (4,292)	\$ (38,379)	\$ 532	\$ 1,253	\$ 2,011

- (1) Income (loss) before income taxes reflects gas and oil production revenues less gas and oil production expenses, general and administrative expenses, depletion, depreciation, and amortization expenses for all periods presented. The Successor three and nine months ended September 30, 2017 include \$5.2 million of loss on asset sale resulting from the closing of the Rangely Asset sale. The Successor nine months ended September 30, 2017 also includes \$38.2 million loss on divestiture resulting from the carrying value of the Rangely Assets exceeding the fair value less costs to sell as disclosed above.

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The following is a summary of property, plant and equipment at the dates indicated (in thousands):

	September 30, 2017	December 31, 2016
Natural gas and oil properties:		
Proved properties	\$ 519,147	\$ 608,901
Unproved properties	52,767	73,057
Support equipment and other	8,690	8,081
Total natural gas and oil properties	580,604	690,039
Less accumulated depreciation, depletion and amortization	(53,207)	(19,270)
Total property, plant and equipment, net	\$ 527,397	\$ 670,769

During the Successor nine months ended September 30, 2017, the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, we recognized \$0.7 million, \$3.5 million and \$19.6 million, respectively, of non-cash investing activities capital expenditures, which was reflected within the changes in accounts payable and accrued liabilities on our condensed consolidated statements of cash flows.

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds during the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016, and the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 were 9.5%, 8.4%, 7.6%, 6.0% and 6.5%, respectively. The aggregate amount of interest capitalized during the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016, and the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 were \$0.2 million, \$0.4 million, \$0.7 million, \$1.7 million and \$6.5 million, respectively.

For the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016, and the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016, we recorded \$0.4 million, \$1.1 million, \$0.5 million, \$1.3 million and \$4.6 million, respectively, of accretion expense related to our asset retirement obligations within depreciation, depletion and amortization in our condensed consolidated statements of operations.

NOTE 5 DEBT

Total debt consists of the following at the dates indicated (in thousands):

September 30,	December 31,
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	2017	2016
First Lien Credit Facility	\$ 256,273	\$ 435,809
Second Lien Credit Facility	283,523	261,022
Deferred financing costs, net of accumulated amortization of \$686 and \$172, respectively	(1,711)	(2,021)
Total debt, net	538,085	694,810
Less current maturities	(538,085)	(694,810)
Total long-term debt, net	\$	\$

Cash Interest. Total cash payments for interest for the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, were \$7.3 million, \$21.2 million, \$0.5 million and \$53.7 million, respectively. There were no cash payments for interest for the Predecessor period from July 1, 2016 through August 31, 2016 due to our Predecessor's Chapter 11 Filings.

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First Lien Credit Facility

On September 1, 2016, we entered into our \$440 million First Lien Credit Facility with Wells Fargo Bank, National Association (Wells Fargo), as administrative agent, and the lenders party thereto. A summary of the key provisions of the First Lien Credit Facility is as follows (of which certain provisions have been modified through subsequent amendments as described further below):

Borrowing base of a \$410 million conforming reserve based tranche plus a \$30 million non-conforming tranche.

Provides for the issuance of letters of credit, which reduce borrowing capacity.

Obligations are secured by mortgages on substantially all of our oil and gas properties and first priority security interests in substantially all of our assets and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

Borrowings bear interest at our election at either LIBOR plus an applicable margin between 3.00% and 4.00% per annum or the alternate base rate plus an applicable margin between 2.00% and 3.00% per annum, which fluctuates based on utilization. We are also required to pay a fee of 0.50% per annum on the unused portion of the borrowing base. At September 30, 2017, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 5.2%.

Contains covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of our assets.

Requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017.

We were not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. On April 19, 2017, we, Titan Energy Operating, LLC (our wholly owned subsidiary), as borrower, and certain subsidiary guarantors entered into a third amendment to the First Lien Credit Facility with Wells Fargo, as administrative agent, and the lenders party thereto. Pursuant to the third amendment, certain of the financial ratio covenants were revised upwards. Specifically, beginning December 31, 2017, we will be required to maintain a ratio of Total Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 5.50 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 5.00 to 1.00 thereafter. We will also be required, beginning December 31, 2017, to maintain a ratio of First Lien Debt (as defined in the First Lien Credit Facility) to EBITDA of not more than 4.00 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 3.50 to 1.00 thereafter.

In addition to the amendments to the financial ratio covenants, the First Lien Credit Facility lenders waived certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a going concern qualification. The First Lien Credit Facility lenders' waivers were subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the 180-day standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Credit Facility.

The third amendment to the First Lien Credit Facility confirmed the conforming and non-conforming tranches of the borrowing base at \$410 million and \$30 million, respectively, but required us to take actions (which included asset sales) to reduce the conforming tranche of the borrowing base to \$330 million by August 31, 2017 and to \$190 million by October 1, 2017 (subject to extension at the administrative agent's option to October 31, 2017). Similarly, the non-conforming tranche of the borrowing base was required to be reduced to \$10 million by November 1, 2017. In addition, we were required to use excess asset sale proceeds (after application in accordance with the existing terms of the First Lien Credit Facility) to repay outstanding borrowings and reduce the applicable borrowing base to the required level.

On June 30, 2017, we completed a majority of the Appalachian Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility. On August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility and achieve compliance with the requirement to reduce our First Lien Credit Facility borrowings below \$360 million, as required by August 31, 2017. On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

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On November 6, 2017, we entered into a fourth amendment to our First Lien Credit Facility. The fourth amendment has an effective date of October 31, 2017 and confirms the conforming and non-conforming tranches of the borrowing base at \$228.7 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$190 million by December 8, 2017 and to \$150 million by August 31, 2018. The maturity date of the non-conforming tranche of the borrowing base was confirmed as May 1, 2018. We are required to use proceeds from asset sales to make prepayments.

In addition to the requirements above, the First Lien Credit Facility lenders also agreed to a limited waiver of certain existing defaults with respect to financial covenants, required repayments of borrowings and other related matters. The waiver terminates upon the earliest of (i) December 8, 2017, (ii) the occurrence of additional events of default under the First Lien Credit Facility and (iii) the exercise of remedies under our Second Lien Credit Facility. Pursuant to the fourth amendment, we are required to hedge at least 50% and 80% of our 2019 projected proved developed producing production by December 31, 2017 and March 31, 2018, respectively.

Second Lien Credit Facility

On September 1, 2016, we entered into our Second Lien Credit Facility with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto for an aggregate principal amount of \$252.5 million maturing on February 23, 2020. A summary of the key provisions of the Second Lien Credit Facility is as follows (of which certain provisions have been modified through subsequent amendments as described further below):

Until May 1, 2017, interest will be payable at a rate of 2% in cash plus paid-in-kind interest at a rate equal to the Adjusted LIBO Rate (as defined in the Second Lien Credit Facility) plus 9% per annum. During the subsequent 15-month period, cash and paid-in-kind interest will vary based on a pricing grid tied to our leverage ratio under the First Lien Credit Facility. After such 15-month period, interest will accrue at a rate equal to the Adjusted LIBO Rate plus 9% per annum and will be payable in cash.

All prepayments are subject to the following premiums, plus accrued and unpaid interest:

4.5% of the principal amount prepaid for prepayments prior to February 23, 2017;

2.25% of the principal amount prepaid for prepayments on or after February 23, 2017 and prior to February 23, 2018; and

no premium for prepayments on or after February 23, 2018.

Obligations are secured on a second priority basis by security interests in the same collateral securing the First Lien Credit Facility and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

Contains covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions, engage in other business activities, and other covenants substantially similar to those in the First Lien Credit Facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables.

Requires us to maintain certain financial ratios (the financial ratios used an annualized EBITDA measurement for periods prior to June 30, 2017):

EBITDA to Interest Expense (each as defined in the Second Lien Credit Facility) of not less than 2.50 to 1.00;

Total Leverage Ratio (as defined in the Second Lien Credit Facility) of no greater than 5.5 to 1.0 prior to December 31, 2017 and no greater than 5.0 to 1.0 thereafter; and

Current assets to current liabilities (each as defined in the Second Lien Credit Facility) of not less than 1.0 to 1.0.

On April 21, 2017, the lenders under the our Second Lien Credit Facility delivered a Notice, pursuant to which they noticed events of default related to financial covenants and the failure to deliver financial statements without a going concern qualification. The delivery of the Notice began the 180-day standstill period under the intercreditor agreement, during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility. The lenders have not accelerated the payment of amounts outstanding under the Second Lien Credit Facility.

On September 27, 2017, the lenders under our Second Lien Credit Facility entered into the Extension Letter with us and the lenders under our First Lien Credit Facility. Pursuant to the Extension Letter, the Second Lien Credit Facility lenders agreed to extend the 180-day standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing the Company's obligations under the Second Lien Credit Facility) by

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an additional 35 days from October 18, 2017 to November 22, 2017. In addition, the extension of the standstill period extends the waiver of certain defaults under the First Lien Credit Facility, which terminates 15 business days prior to the expiration of the standstill period. The parties agreed to extend the standstill period to provide the Company with additional time to negotiate proposed amendments to each of the First Lien Credit Facility and the Second Lien Credit Facility.

In connection with, and as a condition to, the effectiveness of the fourth amendment to our First Lien Credit Facility, on November 6, 2017, the lenders under our Second Lien Credit Facility agreed to extend the standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility are prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility) until December 29, 2017.

NOTE 6 DERIVATIVE INSTRUMENTS

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price risk management activities. We do not apply hedge accounting to any of our derivative instruments. As a result, gains and losses associated with derivative instruments are recognized in earnings.

We enter into commodity future option contracts to achieve more predictable cash flows by hedging our exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile Stock Exchange (NYMEX) futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the physical delivery of the commodity. Crude oil contracts are based on a West Texas Intermediate (WTI) index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts were recorded at their fair values.

Pursuant to the Restructuring Support Agreement, our Predecessor completed the sale of substantially all of its commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay \$233.5 million of borrowings outstanding under the Predecessor's first lien credit facility.

The following table summarizes the commodity derivative activity and presentation in our condensed consolidated statements of operations for the periods indicated (in thousands):

	Successor			Predecessor	
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Period from January 1, 2016 through August 31, 2016
Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets ⁽¹⁾⁽²⁾	\$	\$	\$	\$ 1,461	\$ 10,387
Portion of settlements attributable to subsequent mark to market gains (losses) ⁽²⁾	1,666	(2,309)	191	3,440	80,604

Total cash settlements on commodity derivative contracts ⁽²⁾	\$ 1,666	\$ (2,309)	\$ 191	\$ 4,901	\$ 90,991
Gains (losses) recognized on cash settlement ⁽³⁾	\$ 195	\$ 20,409	\$ (43)	\$ 9,381	\$ (9,444)
Gains (losses) recognized on open derivative contracts ⁽³⁾	(4,263)	16,516	(2,036)	(7,028)	(13,804)
Gains (losses) on mark-to-market derivatives	\$ (4,068)	\$ 36,925	\$ (2,079)	\$ 2,353	\$ (23,248)

(1) Recognized in gas and oil production revenue.

(2) The Predecessor periods presented exclude the effects of the \$214.9 million and the \$20.4 million allocated to discontinued operations (see Note 3), net of \$8.2 million in hedge monetization fees, paid directly to the First Lien Credit Facility lenders upon the sale of substantially all of our Predecessor's commodity hedge positions on July 25, 2016 and July 26, 2016. The \$8.2 million in hedge monetization fees was not allocated to discontinued operations as this was recorded in reorganization items, net on the condensed consolidated statements of operations.

(3) Recognized in gain (loss) on mark-to-market derivatives.

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The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities included on our condensed consolidated balance sheets for the periods indicated (in thousands):

	Gross Amounts Recognized	Gross Amounts Offset	Net Amount Presented
<u>Offsetting Derivatives as of September 30, 2017</u>			
Current portion of derivative assets	\$ 2,038	\$ (2,006)	\$ 32
Long-term portion of derivative assets	168	(168)	
Total derivative assets	\$ 2,206	\$ (2,174)	\$ 32
Current portion of derivative liabilities	\$ (5,635)	\$ 2,006	\$ (3,629)
Long-term portion of derivative liabilities	(1,064)	168	(896)
Total derivative liabilities	\$ (6,699)	\$ 2,174	\$ (4,525)
<u>Offsetting Derivatives as of December 31, 2016</u>			
Current portion of derivative assets	\$ 7	\$ (7)	\$
Long-term portion of derivative assets	677	(677)	
Total derivative assets	\$ 684	\$ (684)	\$
Current portion of derivative liabilities	\$ (30,526)	\$ 7	\$ (30,519)
Long-term portion of derivative liabilities	(13,885)	677	(13,208)
Total derivative liabilities	\$ (44,411)	\$ 684	\$ (43,727)

At September 30, 2017, we had the following commodity derivatives instruments:

Type	Production Period Ending December 31,	Volumes ⁽¹⁾	Average Fixed Price ⁽²⁾	Fair Value		Total Type (in thousands) ⁽²⁾
				Asset / (Liability)	(in thousands)	
Natural Gas Fixed Price Swaps	2017 ⁽³⁾	12,919,900	\$ 3.140	\$	693	
	2018	43,947,300	\$ 2.959	\$	(3,458)	\$ (2,765)
Crude Oil Fixed Price Swaps	2017 ⁽³⁾	196,500	\$ 47.441	\$	(766)	
	2018	588,500	\$ 50.286	\$	(936)	
	2019	73,000	50.630		(26)	\$ (1,728)
				Total net liability	\$	(4,493)

- (1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.
- (2) Fair value for natural gas fixed price swaps are based on forward NYMEX natural gas prices, as applicable. Fair value of crude oil fixed price swaps are based on forward West Texas Intermediate (WTI) index crude oil prices, as applicable.
- (3) The production volumes for 2017 include the remaining three months of 2017 beginning October 1, 2017.

NOTE 7 FAIR VALUE OF FINANCIAL INSTRUMENTS

Assets and Liabilities Measured on a Recurring Basis

We use a market approach fair value methodology to value our outstanding derivative contracts. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into the three level hierarchy (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 fair value. As of September 30, 2017 and December 31, 2016, all of our derivative financial instruments were classified as Level 2.

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Information for financial instruments measured at fair value were as follows (in thousands):

Derivatives, Fair Value, as of September 30, 2017	Level 1	Level 2	Level 3	Total
Assets, gross				
Commodity swaps	\$	\$ 2,206	\$	\$ 2,206
Total derivative assets, gross		2,206		2,206
Liabilities, gross				
Commodity swaps		(6,699)		(6,699)
Total derivative liabilities, gross		(6,699)		(6,699)
Total derivatives, fair value, net	\$	\$ (4,493)	\$	\$ (4,493)
Derivatives, Fair Value, as of December 31, 2016	Level 1	Level 2	Level 3	Total
Assets, gross				
Commodity swaps	\$	\$ 684	\$	\$ 684
Total derivative assets, gross		684		684
Liabilities, gross				
Commodity swaps		(44,411)		(44,411)
Total derivative liabilities, gross		(44,411)		(44,411)
Total derivatives, fair value, net	\$	\$ (43,727)	\$	\$ (43,727)

Other Financial Instruments

Our other current assets and liabilities on our condensed consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair value of our long-term debt at September 30, 2017, which consists of our First Lien Credit Facility and Second Lien Credit Facility, approximated carrying value of \$539.8 million. At September 30, 2017, the carrying value of outstanding borrowings under our First Lien Credit Facility, which bears interest at variable interest rates, approximated estimated fair value. The estimated fair value of our Second Lien Credit Facility was based upon the market approach and calculated using yields of our Second Lien Credit Facility as provided by financial institutions and thus were categorized as Level 3 values.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

We estimated the fair value less estimated costs to sell of our remaining Appalachia Assets and Rangely Assets held for sale (see Note 3) based on the respective negotiated purchase prices that were derived from discounted cash flow models, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, the respective natural gas, oil and natural gas liquids forward price curves, external

estimates of recovery values, and other market multiples. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

Our Predecessor's management estimated the fair values of natural gas and oil properties transferred to our Predecessor upon consolidation of certain Drilling Partnerships (see Note 8) based on a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, our Predecessor's future operating and development costs of the assets, the respective natural gas, oil and natural gas liquids forward price curves and estimated salvage values using our historical experience and external estimates of recovery values. These estimates of fair value were Level 3 measurements as they were based on unobservable inputs.

Our Predecessor's management estimated the fair value of asset retirement obligations transferred to our Predecessor upon consolidation of certain Drilling Partnerships (see Note 8) based on discounted cash flow projections using our Predecessor's historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future considering inflation rates, federal and state regulatory requirements, and our Predecessor's assumed credit-adjusted risk-free interest rate. These estimates of fair value were Level 3 measurements as they were based on unobservable inputs.

We estimated the fair value of our enterprise value and reorganizational value of assets and liabilities upon our emergence from bankruptcy through fresh-start accounting (see Note 2) utilizing the discounted cash flow method for both our gas and oil production business and our partnership management business based on the financial projections in our disclosure statement. The resulting fair value of our equity was used to value shares issued under our incentive plan. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

Table of Contents**NOTE 8 CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS**

Relationship with ATLS. Except for our named executive officers, we do not directly employ any persons to manage or operate our business. These functions are provided by employees of ATLS and/or its affiliates. As of September 30, 2017, we had a \$1.8 million payable to ATLS for payroll and benefit costs related to ATLS employees managing and operating our business, which was recorded as a current liability within advances from affiliates on our condensed consolidated balance sheet. As of September 30, 2017 we reclassified \$15.1 million of receivables from ATLS originating prior to our Chapter 11 Filings to non-current due to the uncertainty of collecting this balance within the next twelve months, which was recorded within non-current advances to affiliates on our condensed consolidated balance sheet. As of December 31, 2016, we had net receivables of \$3.3 million from ATLS related to the timing of funding cash accounts related to general and administrative expenses, such as payroll and benefits, and amounts originating prior to our Chapter 11 Filings, which was recorded as a net current asset within in advances to affiliates in our condensed consolidated balance sheets.

Relationship with Drilling Partnerships. We conduct certain activities through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. We serve as general partner and operator of the Drilling Partnerships and assume customary rights and obligations for the Drilling Partnerships. As the general partner, we are liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the Drilling Partnerships if we breach our responsibilities with respect to the operations of the Drilling Partnerships. We are entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership's revenue and costs and expenses according to the respective partnership agreements. On June 30, 2017, in connection with the completion of the sale of the majority of the Appalachian Assets, we delegated the operational activities to an affiliate of Diversified for all the Drilling Partnerships' natural gas and oil wells in Pennsylvania and Tennessee.

In March 2016, our Predecessor transferred \$36.7 million of investor capital raised and \$13.3 million of accrued well drilling and completion costs incurred by our Predecessor to the Atlas Eagle Ford 2015 L.P. private drilling partnership for activities directly related to their program. In June 2016, our Predecessor transferred \$3.8 million of funds to certain of the Drilling Partnerships that were projected to make monthly or quarterly distributions to their limited partners over the next several months and/or quarters to ensure accessible distribution funding coverage in accordance with the respective Drilling Partnerships' operations and partnership agreements in the event that our Predecessor experienced a prolonged restructuring period as our Predecessor performed all administrative and management functions for the Drilling Partnerships.

During the Predecessor period from January 1, 2016 to August 31, 2016, our Predecessor recorded \$7.2 million and \$12.4 million of gas and oil properties and asset retirement obligations, respectively, transferred to our Predecessor as a result of certain Drilling Partnership consolidations. The gas and oil properties and asset retirement obligations were recorded at their fair values on the respective dates of the Drilling Partnerships' consolidation and transfer to our Predecessor (see Note 7) and resulted in a non-cash loss of \$6.1 million, net of consolidation and transfer adjustments, for the Predecessor period from January 1, 2016 through August 31, 2016, which was recorded in net income (loss) from discontinued operations in the consolidated statements of operations.

During the Predecessor periods from July 1, 2016 to August 31, 2016 and from January 1, 2016 to August 31, 2016, we recognized a \$10.9 million provision for losses on Drilling Partnership receivables related to the write down of certain receivables to their estimated net realizable values, which is recorded in loss from discontinued operations on our consolidated statement of operations. As of December 31, 2016, we had trade receivables of \$0.1 million from certain of the Drilling Partnerships, which were recorded in accounts receivable in our condensed consolidated balance sheet. As of September 30, 2017 and December 31, 2016, we had trade payables of \$3.2 million and \$5.6 million, respectively, to certain of the Drilling Partnerships, which were recorded in accounts payable in our

condensed consolidated balance sheets.

Relationship with AGP. At the direction of ATLS, we charge direct costs, such as salaries and wages, and allocate indirect costs, such as rent and other general and administrative costs, to AGP based on the number of ATLS employees who devoted time to AGP's activities. As of September 30, 2017 and December 31, 2016, we had receivables of \$0.1 million and \$0.8 million, respectively, from AGP related to AGP's direct costs and indirect cost allocation, which was recorded in advances to affiliates in our condensed consolidated balance sheets.

Other Relationships. We have other related party transactions with regard to certain funds advised and sub-advised by GSO Capital Partners LP and its affiliates (GSO) as GSO funds are majority lenders under our Second Lien Credit Facility and GSO funds hold an excess of ten-percent of our common shares.

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NOTE 9 COMMITMENTS AND CONTINGENCIES

Drilling Partnership Commitments

As of September 30, 2017, we are committed to expend approximately \$2.8 million, principally on a new enterprise resource planning system and drilling and completion expenditures.

Environmental Matters

We and our subsidiaries are subject to various federal, state and local laws and regulations relating to the protection of the environment. We have established procedures for the ongoing evaluation of our and our subsidiaries' operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. We and our subsidiaries maintain insurance which may cover in whole or in part certain environmental expenditures. We and our subsidiaries had no environmental matters requiring specific disclosure or requiring the recognition of a liability as of September 30, 2017 and December 31, 2016.

Legal Proceedings

We are party to various routine legal proceedings arising out of the ordinary course of our business. We believe that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

NOTE 10 PREDECESSOR CASH DISTRIBUTIONS

Our Predecessor had a monthly cash distribution program whereby it distributed all of its available cash (as defined in its partnership agreement) for that month to its unitholders within 45 days from the month end. If our Predecessor's common unit distributions in any quarter exceed specified target levels, ATLS received between 13% and 48% of such distributions in excess of the specified target levels.

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid four monthly cash distributions totaling \$5.1 million to its common limited partners (\$0.0125 per unit per month); \$2.5 million to its Preferred Class C limited partners (\$0.0125 per unit per month); and \$0.2 million to its General Partner Class A holder (\$0.0125 per unit per month).

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling \$4.4 million to its Class D Preferred limited partners (\$0.5390625 per unit) for the period October 15, 2015 through April 14, 2016. During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling \$0.3 million to its Class E Preferred limited partners (\$0.671875 per unit) for the period October 15, 2015 through April 14, 2016. On June 16, 2016, our Predecessor's Board of Directors elected to suspend its quarterly distributions on its Class D Preferred Units and our Class E Preferred Units, beginning with the second quarter 2016 distribution, due to the continued lower commodity price environment. The Class D Preferred Units and Class E Preferred Units accrued distributions of \$3.4 million and \$0.3 million, respectively, from April 15, 2016 through August 31, 2016. However, due to the distribution suspension and our Predecessor's Chapter 11 filings, these amounts were not earned as the preferred units were cancelled without receipt of any consideration on the Plan Effective Date.

NOTE 11 OPERATING SEGMENT INFORMATION

Our operations include two reportable operating segments: gas and oil production and Drilling Partnership management. The Drilling Partnership management segment includes all of our managing and operating activities specific to the Drilling Partnerships including well construction and completion, administration and oversight, well services, and gathering and processing. These operating segments reflect the way we manage our operations and make business decisions.

We previously presented three reportable operating segments; however, due to the decline in investor capital funds raised in recent years, anticipated lower levels of future investor capital fund raise, and the consolidation of certain historical Drilling Partnerships in 2016, we aggregated our well construction and completion segment with our other partnership management segment to report all of our Drilling Partnership management activities in one combined segment as they do not meet the quantitative threshold for reporting individual segment information. As a result of this change, we have restated our prior year condensed consolidated statements of operations and segment footnote disclosures to conform to our current presentation.

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Operating segment data for the periods indicated were as follows (in thousands):

	Successor Three Months Period Ended September 1 September 30, through 2017	September 1 30, 2016	Predecessor Period July 1 through August 31, 2016
Gas and oil production:			
Gas and oil production revenues ⁽¹⁾	\$ 43,356	\$ 15,182	\$ 38,643
Gas and oil production costs	(21,633)	(9,854)	(18,577)
Depreciation, depletion and amortization	(11,646)	(4,882)	(14,723)
Loss on divestiture	(5,177)		
Segment income	\$ 4,900	\$ 446	\$ 5,343
Drilling partnership management:⁽²⁾			
Drilling partnership management revenues	\$ 1,997	\$ 2,074	\$ 18,778
Drilling partnership management expenses	(248)	(1,266)	(16,121)
Depreciation, depletion and amortization expense	(288)	(270)	(5,862)
Segment income (loss)	\$ 1,461	\$ 538	\$ (3,205)
Reconciliation of segment income (loss) to net loss:			
Segment income (loss):			
Gas and oil production	\$ 4,900	\$ 446	\$ 5,343
Drilling partnership management ⁽²⁾	1,461	538	(3,205)
Total segment income	6,361	984	2,138
General and administrative expenses ⁽³⁾	(10,142)	(4,530)	(5,128)
Interest expense ⁽³⁾	(15,268)	(3,470)	(14,087)
Gain (loss) on asset sales and disposal ⁽³⁾	(82)	5	(18)
Reorganization items, net ⁽³⁾		(353)	(16,614)
Other income (loss) ⁽³⁾	(777)		(3,063)
Income tax (provision) benefit ⁽³⁾	202		
Net loss	\$ (19,706)	\$ (7,364)	\$ (36,772)
Reconciliation of segment revenues to total revenues:			
Gas and oil production ⁽¹⁾	\$ 43,356	\$ 15,182	\$ 38,643
Drilling partnership management	1,997	2,074	18,778
Total revenues	\$ 45,353	\$ 17,256	\$ 57,421

Capital expenditures:

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Gas and oil production	\$ 4,279	\$ 5,464	\$ 5,529
Drilling partnership management		(115)	496
Corporate and other	325	18	49
Total capital expenditures	\$ 4,604	\$ 5,367	\$ 6,074

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	Successor		Predecessor
	Nine Months	Period	Period
	Ended	September 1	January 1 through
	September 30,	through	August 31, 2016
	2017	30, 2016	
Gas and oil production:			
Gas and oil production revenues ⁽¹⁾	\$ 197,855	\$ 15,182	\$ 105,829
Gas and oil production costs	(74,355)	(9,854)	(80,988)
Depreciation, depletion and amortization	(37,455)	(4,882)	(62,142)
Loss on divestiture	(43,369)		
Segment income (loss)	\$ 42,676	\$ 446	\$ (37,301)
Drilling partnership management:⁽²⁾			
Drilling partnership management revenues	\$ 17,387	\$ 2,074	\$ 24,446
Drilling partnership management expenses	(10,026)	(1,266)	(17,427)
Depreciation, depletion and amortization expense	(947)	(270)	(11,130)
Segment income (loss)	\$ 6,414	\$ 538	\$ (4,111)
Reconciliation of segment income (loss) to net loss:			
Segment income (loss):			
Gas and oil production ⁽¹⁾	\$ 42,676	\$ 446	\$ (37,301)
Drilling partnership management	6,414	538	(4,111)
Total segment income (loss)	49,090	984	(41,412)
General and administrative expenses ⁽³⁾	(32,961)	(4,530)	(41,038)
Interest expense ⁽³⁾	(41,816)	(3,470)	(71,059)
Gain on early extinguishment of debt ⁽³⁾			26,498
Gain (loss) on asset sales and disposal ⁽³⁾	25	5	(551)
Reorganization items, net ⁽³⁾		(353)	(16,614)
Other income (loss) ⁽³⁾	(925)		(3,063)
Income tax (provision) benefit ⁽³⁾	11,503		
Net loss	\$ (15,084)	\$ (7,364)	\$ (147,239)
Reconciliation of segment revenues to total revenues:			
Gas and oil production ⁽¹⁾	\$ 197,855	\$ 15,182	\$ 105,829
Drilling partnership management	17,387	2,074	24,446
Total revenues	\$ 215,242	\$ 17,256	\$ 130,275
Capital expenditures:			
Gas and oil production	\$ 36,191	\$ 5,464	\$ 22,684
Drilling partnership management	521	(115)	2,046
Corporate and other	527	18	164

Total capital expenditures	\$ 37,239	\$ 5,367	\$ 24,894
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- (1) Includes gain (loss) on mark-to-market derivatives. The Predecessor period from January 1, 2016 through August 31, 2016 includes a \$23.2 million loss on mark-to-market derivatives related to increases in commodity future prices relative to our commodity fixed price swaps.
- (2) Includes revenues and expenses from our Drilling Partnership management activities, including well construction and completion, well services, gathering and processing, administration and oversight that do not meet the quantitative threshold for reporting individual segment information.
- (3) General and administrative expenses, interest expense, gain on early extinguishment of debt, gain (loss) on asset sales and disposal, reorganization items, net,, other income (loss) and income tax (provision) benefit have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented.

	September 30, 2017	December 31, 2016
Balance sheet:		
Total assets:		
Gas and oil production	\$ 556,607	\$ 703,243
Drilling partnership management	5,476	11,786
Corporate and other ⁽¹⁾	43,342	44,129
Assets held for sale		122,676
Total assets	\$ 605,425	\$ 881,834

- (1) Corporate and other primarily consists of cash and cash equivalents, advances to affiliates and other assets, net, which have not been allocated to reportable segments.

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ITEM 2: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS OVERVIEW

We are a publicly traded (OTCQX: TTEN) Delaware limited liability company and an independent developer and producer of natural gas, crude oil and NGLs with operations in basins across the United States but primarily focused on the horizontal development of resource potential from the Eagle Ford Shale in South Texas. As discussed further below, we are the successor to the business and operations of Atlas Resource Partners, L.P. (ARP). Unless the context otherwise requires, references to Titan Energy, LLC, Titan, the Company, we, us, and our, refer to Titan Energy and our consolidated subsidiaries (and our predecessor, where applicable).

Titan Energy Management, LLC (Titan Management) manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of Atlas Energy Group, LLC (ATLS ; OTCQX: ATLS), which is a publicly traded company.

In addition to its preferred member interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (AGP), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the Restructuring Support Agreement) with certain of their lenders (the Restructuring Support Parties) to support ARP's restructuring pursuant to a pre-packaged plan of reorganization (the Plan).

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 in the United States Bankruptcy Court for the Southern District of New York (the Bankruptcy Court, and the cases commenced thereby, the Chapter 11 Filings). The cases commenced thereby were jointly administered under the caption In re: ATLAS RESOURCE PARTNERS, L.P., et al.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the Plan Effective Date), pursuant to the Plan, the following occurred:

ARP's first lien lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than \$440 million of principal and face amount of letters of credit) and became lenders under our first lien exit facility credit agreement, composed of a \$410 million conforming reserve-based tranche and a \$30 million non-conforming tranche (the First Lien Credit Facility).

ARP's second lien lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of \$252.5 million (the Second Lien Credit Facility). In addition, ARP's second lien lenders received a pro rata share of 10% of our common shares, subject to dilution by a management

incentive plan.

ARP's senior note holders, in exchange for 100% of the \$668 million aggregate principal amount of senior notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

all of ARP's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended.

Titan Management, a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. Four of the seven initial members of the board of directors were designated by Titan Management (the Titan Class A Directors). For so long as Titan Management holds such preferred share, the Titan Class A Directors will be appointed by a majority of the Titan Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market

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value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

LIQUIDITY AND ABILITY TO CONTINUE AS A GOING CONCERN

Since the Plan Effective Date, we have funded our operations through cash flows generated from our operations and cash on hand. We currently do not have the capacity to access additional liquidity from our First Lien Credit Facility and our ability to access public equity and debt markets may be limited. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and continue to remain low in 2017. These lower commodity prices have negatively impacted our revenues, earnings and cash flows, which has negatively impacted our ability to remain in compliance with the covenants under our credit facilities. Sustained low commodity prices could have a material and adverse effect on our liquidity position.

Even following the amendments described below, we continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. If we are not able to enter into further amendments with our lenders prior to the expiration of the standstill period, we may be forced to seek further options as described below.

We were not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. As a result of the amendment referenced below, our financial covenants will not be tested again until the quarter ending December 31, 2017. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. We have classified \$538.1 million of outstanding indebtedness under our credit facilities, which is net of \$1.7 million of deferred financing costs, as current portion of long term debt, net within our condensed consolidated balance sheet as of September 30, 2017, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit.

On April 19, 2017, we entered into an amendment to our First Lien Credit Facility (which has been superseded by subsequent amendments as described further below). This amendment provided for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base (*refer to Note 5 of our condensed consolidated financial statements for further information regarding the specific amended terms and provisions*). As part of our overall business strategy, we have continued to execute on our sales of non-core assets, which has included the sale of our Appalachia and Rangely operations (*see Recent Developments*). The proceeds of the consummated asset sales were used to repay borrowings under our First Lien Credit Facility. Our strategy is to continue to sell non-core assets to reduce our leverage position, which will also help us to comply with the requirements of our First Lien Credit Facility amendments.

In addition to the amendments to the financial ratio covenants, the First Lien Credit Facility lenders waived certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a going concern qualification. The First Lien Credit Facility lenders' waivers were subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our Second Lien Credit Facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Credit Facility.

On April 21, 2017, the lenders under the our Second Lien Credit Facility delivered a notice of events of default and reservation of rights, pursuant to which they noticed events of default related to financial covenants and the failure to deliver financial statements without a going concern qualification. The delivery of such notice began the 180-day standstill period under the intercreditor agreement, during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility. The lenders have not accelerated the payment of amounts outstanding under the Second Lien Credit Facility.

On September 27, 2017, the lenders under our Second Lien Credit Facility entered into a letter agreement with us and the lenders under our First Lien Credit Facility (the Extension Letter) (which has been superseded by subsequent amendments as described further below). Pursuant to the Extension Letter, the Second Lien Credit Facility lenders agreed to extend the 180-day standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing the Company s obligations under the Second Lien Credit Facility) by an additional 35 days from October 18, 2017 to November 22, 2017. In addition, the extension of the standstill period extended the waiver of certain defaults under the First Lien Credit Facility, which terminates 15 business days prior to the expiration of the standstill period. The parties agreed to extend the standstill period to provide the Company with additional time to negotiate proposed amendments to each of the First Lien Credit Facility and the Second Lien Credit Facility.

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On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

On November 6, 2017, we entered into a fourth amendment to our First Lien Credit Facility. The fourth amendment has an effective date of October 31, 2017 and confirms the conforming and non-conforming tranches of the borrowing base at \$228.7 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$190 million by December 8, 2017 and to \$150 million by August 31, 2018. The maturity date of the non-conforming tranche of the borrowing base was confirmed as May 1, 2018. We are required to use proceeds from asset sales to make prepayments.

In addition to the requirements above, the First Lien Credit Facility lenders also agreed to a limited waiver of certain existing defaults with respect to financial covenants, required repayments of borrowings and other related matters. The waiver terminates upon the earliest of (i) December 8, 2017, (ii) the occurrence of additional events of default under the First Lien Credit Facility and (iii) the exercise of remedies under our Second Lien Credit Facility. Pursuant to the fourth amendment, we are required to hedge at least 50% and 80% of our 2019 projected proved developed producing production by December 31, 2017 and March 31, 2018, respectively.

In connection with, and as a condition to, the effectiveness of the fourth amendment to our First Lien Credit Facility, the lenders under our Second Lien Credit Facility agreed to extend the standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility are prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility) until December 29, 2017.

We continually review and may make changes to our capital structure from time to time, with the goal of strengthening our balance sheet and meeting our debt service obligations. We could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options, but there is no certainty that we will be able to implement any such options, and we cannot provide any assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders.

We cannot assure you that we will be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that will be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions will allow us to meet our debt obligations and capital requirements.

RECENT DEVELOPMENTS

Appalachia Divestiture

On May 4, 2017, we entered into a definitive agreement to sell our conventional Appalachia and Marcellus assets to Diversified Gas & Oil, PLC (Diversified) for \$84.2 million. The transaction includes the sale of approximately 8,400 oil and gas wells across Pennsylvania, Ohio, Tennessee, New York and West Virginia, along with the associated infrastructure (the Appalachia Assets). We retained our Utica Shale position, Indiana assets and West Virginia CBM assets in the region. On June 30, 2017, we completed a majority of the Appalachia Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility.

On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

Rangely Divestiture

On June 12, 2017, we entered into a definitive agreement to sell our 25% interest in Rangely Field to an affiliate of Merit Energy Company, LLC for \$105 million. Rangely is a CO₂ flood located in Rio Blanco County, Colorado, and operated by Chevron. The transaction includes the sale of our interest in Rangely Field, its 22% interest in Raven Ridge Pipeline, a CO₂ transportation line, as well as surrounding acreage in Rio Blanco and Moffat Counties, Colorado (collectively, the Rangely Assets). On August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility and achieve compliance with the requirement to reduce our First Lien Credit Facility borrowings below \$360 million, as required by August 31, 2017.

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GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by key trends in natural gas and oil production markets. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

The natural gas, oil and natural gas liquids commodity price markets have suffered significant declines since the fourth quarter of 2014 and continue to remain low in 2017. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, and our ability to make payments on our debts, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas and oil production from particular wells decrease. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. To the extent we do not have sufficient capital, our ability to drill and acquire more reserves will be negatively impacted. Based on current market conditions, we believe that a reduction in our debt and cash interest obligations is needed to improve our financial position and flexibility and to position us to take advantage of opportunities that may arise out of the current industry downturn.

RESULTS OF OPERATIONS

We sponsored and continue to manage tax-advantaged investment partnerships (the *Drilling Partnerships*), in which we coinvested, to finance a portion of our natural gas, crude oil and NGL production activities.

Matters Impacting Comparability of Results

Fresh Start Accounting. Upon our emergence from bankruptcy, we adopted fresh-start accounting in accordance with ASC 852. We qualified for fresh-start accounting because (i) the reorganization value of our assets immediately prior to the confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of existing voting shares of our predecessor company received less than 50% of the voting shares of the post-emergence successor entity.

As a result of the application of fresh start accounting, at the Plan Effective Date, our assets and liabilities were recorded at their estimated fair values which, in some cases, are significantly different than amounts included in our financial statements prior to the Plan Effective Date. Accordingly, our financial condition, results of operations, and cash flows on and after the Plan Effective Date are not comparable to our financial condition, results of operations, and cash flows prior to the Plan Effective Date. References to *Successor* relate to Titan on and subsequent to the Plan Effective Date. References to *Predecessor* refer to ARP prior to the Plan Effective Date. We have presented our financial condition, results of operations, and cash flows with a black line division to delineate the lack of comparability between the amounts presented on or after September 1, 2016 and dates prior.

Reclassifications. Certain reclassifications have been made to our condensed consolidated financial statements for the prior year periods to conform to classifications used in the current year, specifically related to our Appalachian Assets

presented as discontinued operations in the condensed consolidated financial statements and footnote disclosures and our segment information on the condensed consolidated statement of operations and segment footnote disclosures.

Discontinued operations. We determined the Appalachian Assets represent discontinued operations as they constitute a disposal of a group of components and a strategic shift that will have a major effect on our operations and financial results. We evaluated the Appalachian Assets sale on our gas and oil production and Drilling Partnership management segments' results of operations and cash flows, as well as expected asset retirement obligations, and concluded the impact will have a major effect on our expected operations and financial results. As a result, we reclassified the Appalachian Assets from their historical presentation to assets and liabilities held for sale on the condensed consolidated balance sheet and to net income (loss) from discontinued operations on the condensed consolidated statement of operations for all periods presented.

Segments. Our operations include two reportable operating segments: gas and oil production and Drilling Partnership management. The Drilling Partnership management segment includes all of our managing and operating activities specific to the Drilling Partnerships including well construction and completion, administration and oversight, well services, and gathering and processing. These operating segments reflect the way we manage our operations and make business decisions.

We previously presented three reportable operating segments; however, due to the decline in investor capital funds raised in recent years, anticipated lower levels of future investor capital fund raise, and the consolidation of certain historical Drilling

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Partnerships in 2016, we aggregated our well construction and completion segment with our other partnership management segment to report all of our Drilling Partnership management activities in one combined segment as they do not meet the quantitative threshold for reporting individual segment information. As a result of this change, we have restated our prior year condensed consolidated statements of operations and segment footnote disclosures to conform to our current presentation.

GAS AND OIL PRODUCTION

Production Profile. Currently, we have natural gas, crude oil and NGL production operations in various plays throughout the United States. We have established production positions in the following operating areas:

the Eagle Ford Shale in south Texas, in which we acquired acreage and producing wells in November 2014;

Coalbed Methane producing natural gas assets in (1) the Raton Basin in northern New Mexico and southern Colorado, acquired in 2013; (2) the Black Warrior Basin in central Alabama, acquired in 2013; (3) the Central Appalachia Basin in West Virginia and Virginia, acquired in 2014; and (4) the Arkoma Basin in eastern Oklahoma, acquired in 2015;

the Appalachia Basin assets, including the Utica Shale, and the New Albany Shale in southwestern Indiana; and

the Mid-Continent assets, including Barnett Shale and Marble Falls plays, both in the Fort Worth Basin in northern Texas and acquired in 2012, and the Mississippi Lime and Hunton plays in northwestern Oklahoma.

We also had a production position in the Rangely field in northwest Colorado, a mature tertiary CO₂ flood with low-decline oil production, where we had a 25% non-operated net working interest position which we acquired in 2014 and subsequently sold in August 2017.

The following table presents the number of wells we drilled and the number of wells we turned in line, both gross and for our interest, during the periods indicated:

	Successor Period Three Months Ended September 30, 2017	Predecessor Period July 1 through August 31, 2016
Gross wells drilled⁽³⁾:		
Eagle Ford		2
Net wells drilled⁽¹⁾:		
Eagle Ford		2

Gross wells turned in line⁽²⁾⁽³⁾:		
Eagle Ford		4
Net wells turned in line⁽¹⁾⁽²⁾⁽³⁾:		
Eagle Ford		1
	Successor Period Nine Months Ended September 2017	Predecessor Period January 1 through August 31, 2016
Gross wells drilled⁽³⁾:		
Eagle Ford	4	2
Net wells drilled⁽¹⁾:		
Eagle Ford	3	2
Gross wells turned in line⁽²⁾⁽³⁾:		
Eagle Ford	4	4
Net wells turned in line⁽¹⁾⁽²⁾⁽³⁾:		
Eagle Ford	3	1

- (1) Includes (i) our percentage interest in the wells in which we have had a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in the Drilling Partnerships.
- (2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.

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(3) There were no exploratory wells drilled during the periods presented. There were no gross or net dry wells within any of our operating areas during the periods presented.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes per day in each of our operating areas and total production for each of the periods indicated:

	Successor Period Three Months Ended September 30, 2017	September 1, through September 30, 2016	Predecessor Period July 1, through August 31, 2016
Production volumes per day:⁽¹⁾⁽²⁾			
Eagle Ford:			
Natural gas (Mcfed)	613	423	457
Oil (Bpd)	2,218	1,025	1,028
NGLs (Bpd)	136	88	95
Total (Mcfed)	14,736	7,102	7,197
Coal-bed Methane:			
Natural gas (Mcfed)	103,673	114,030	114,100
Oil (Bpd)			
NGLs (Bpd)			
Total (Mcfed)	103,673	114,030	114,100
Utica / Indiana:			
Natural gas (Mcfed)	3,914	4,841	5,136
Oil (Bpd)	20	43	43
NGLs (Bpd)	15	23	25
Total (Mcfed)	4,121	5,240	5,540
Mid-Continent:			
Natural gas (Mcfed)	30,674	34,508	34,499
Oil (Bpd)	193	299	325
NGLs (Bpd)	1,190	1,447	1,440
Total (Mcfed)	38,970	44,985	45,091
Rangely:⁽³⁾			
Natural gas (Mcfed)			
Oil (Bpd)	817	2,229	2,214
NGLs (Bpd)	34	232	242
Total (Mcfed)	5,103	14,766	14,736

Total production volumes per day:			
Natural gas (Mcfed)	138,873	153,802	154,192
Oil (Bpd)	3,247	3,597	3,611
NGLs (Bpd)	1,374	1,790	1,801
Total (Mcfed)	166,602	186,122	186,664
Total production:⁽¹⁾⁽²⁾			
Natural gas (MMcf)	12,776	4,614	9,560
Oil (MBbls)	299	108	224
NGLs (MBbls)	126	54	112
Total (MMcfe)	15,327	5,584	11,573

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	Successor Period Nine Months Ended September 30, 2017	September 1, through September 30, 2016	Predecessor Period January 1, through August 31, 2016
Production volumes per day:⁽¹⁾⁽²⁾			
Eagle Ford:			
Natural gas (Mcfed)	621	423	437
Oil (Bpd)	2,072	1,025	1,212
NGLs (Bpd)	137	88	91
Total (Mcfed)	13,874	7,102	8,257
Coal-bed Methane: ⁽³⁾			
Natural gas (Mcfed)	105,835	114,030	117,491
Oil (Bpd)			
NGLs (Bpd)			
Total (Mcfed)	105,835	114,030	117,491
Utica / Indiana:			
Natural gas (Mcfed)	4,163	4,841	5,748
Oil (Bpd)	26	43	47
NGLs (Bpd)	17	23	25
Total (Mcfed)	4,417	5,240	6,182
Mid-Continent:			
Natural gas (Mcfed)	31,229	34,508	38,111
Oil (Bpd)	225	299	432
NGLs (Bpd)	1,224	1,447	1,654
Total (Mcfed)	39,927	44,985	50,627
Rangely: ⁽³⁾			
Natural gas (Mcfed)			
Oil (Bpd)	1,648	2,229	2,287
NGLs (Bpd)	153	232	244
Total (Mcfed)	10,802	14,766	15,187
Total production volumes per day:			
Natural gas (Mcfed)	141,848	153,802	161,786
Oil (Bpd)	3,971	3,597	3,979
NGLs (Bpd)	1,530	1,790	2,014
Total (Mcfed)	174,855	186,122	197,745

Total production:⁽¹⁾⁽²⁾

Natural gas (MMcf)	38,725	4,614	39,476
Oil (MBbls)	1,084	108	971
NGLs (MBbls)	418	54	491
Total (MMcfe)	47,735	5,584	48,250

- (1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling Partnership's proportionate net revenue interest in these wells.
- (2) MMcf represents million cubic feet; MMcfe represent million cubic feet equivalents; Mcfd represents thousand cubic feet per day; Mcfed represents thousand cubic feet equivalents per day; and Bbls and Bpd represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.
- (3) We sold our interest in Rangely on August 7, 2017 (see Recent Developments).

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Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production, along with our average production costs, which include lease operating expenses, taxes, and transportation costs, for each of the periods indicated:

	Successor		Predecessor
	Three	Period	Period July 1
	Months	September 1	through
	Ended	through	August 31,
	September 30,	September 30,	August 31,
	2017	2016	2016
Production revenues (in thousands):⁽¹⁾			
Eagle Ford:			
Natural gas revenue	\$ 155	\$ 35	\$ 92
Oil revenue	9,699	1,306	1,960
Natural gas liquids revenue	253	45	86
Total revenues	\$ 10,107	\$ 1,386	\$ 2,138
Coal-bed Methane:			
Natural gas revenue	\$ 26,256	\$ 9,628	\$ 22,077
Oil revenue			
Natural gas liquids revenue			
Total revenues	\$ 26,256	\$ 9,628	\$ 22,077
Utica / Indiana:			
Natural gas revenue	\$ 920	\$ 339	\$ 736
Oil revenue	66	50	91
Natural gas liquids revenue	19	7	15
Total revenues	\$ 1,005	\$ 396	\$ 842
Mid-Continent:			
Natural gas revenue	\$ 5,816	\$ 2,165	\$ 5,252
Oil revenue	814	362	624
Natural gas liquids revenue	2,007	609	1,070
Total revenues	\$ 8,637	\$ 3,136	\$ 6,946
Rangely: ⁽⁷⁾			
Natural gas revenue	\$	\$	\$
Oil revenue	2,599	2,843	4,393
Natural gas liquids revenue	118	214	452
Total revenues	\$ 2,717	\$ 3,057	\$ 4,845

Total production revenues:			
Natural gas revenue	\$ 33,147	\$ 12,167	\$ 28,157
Oil revenue	13,178	4,561	7,068
Natural gas liquids revenue	2,397	875	1,623
Subordinated revenue ⁽²⁾	(1,298)	(342)	(558)
Total revenues	\$ 47,424	\$ 17,261	\$ 36,290
Average sales price:			
Natural gas (per Mcf): ⁽³⁾			
Total realized price, after hedge ^{(4) (1)}	\$ 2.74	\$ 2.70	\$ 3.06
Total realized price, before hedge ⁽⁴⁾	\$ 2.60	\$ 2.61	\$ 2.53
Oil (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 43.55	\$ 39.92	\$ 41.09
Total realized price, before hedge	\$ 44.05	\$ 42.21	\$ 41.68
Natural gas liquids (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 18.96	\$ 16.30	\$ 14.53
Total realized price, before hedge	\$ 18.96	\$ 16.30	\$ 14.53

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	Successor Three Months Ended September 30, 2017	Predecessor Period September 1 through September 30, 2016	Predecessor Period July 1 through August 31, 2016
Production costs (per Mcfe):⁽³⁾			
Eagle Ford:			
Lease operating expenses	\$ 1.22	\$ 2.03	\$ 1.58
Production taxes	0.39	0.49	0.48
Transportation and compression	0.05	0.14	0.16
	\$ 1.66	\$ 2.66	\$ 2.23
Coal-bed Methane:			
Lease operating expenses	\$ 1.08	\$ 1.06	\$ 0.97
Production taxes	0.20	0.24	0.21
Transportation and compression	0.10	0.19	0.18
	\$ 1.37	\$ 1.48	\$ 1.37
Utica / Indiana:			
Lease operating expenses	\$ 0.54	\$ 0.46	\$ 0.34
Production taxes	0.12	0.06	0.06
Transportation and compression	0.08	0.12	0.11
	\$ 0.74	\$ 0.65	\$ 0.51
Mid-Continent:			
Lease operating expenses	\$ 0.90	\$ 0.99	\$ 0.85
Production taxes	0.15	0.20	0.19
Transportation and compression	0.18	0.23	0.25
	\$ 1.23	\$ 1.42	\$ 1.29
Rangely:⁽⁷⁾			
Lease operating expenses	\$ 4.53	\$ 4.59	\$ 4.22
Production taxes	0.12	0.62	0.60
Transportation and compression	0.02	0.01	0.01
	\$ 4.67	\$ 5.22	\$ 4.82
Total production costs:			
Lease operating expenses ⁽⁵⁾	\$ 1.14	\$ 1.34	\$ 1.20
Production taxes	0.20	0.27	0.24
Transportation and compression	0.11	0.18	0.18
	\$ 1.45	\$ 1.79	\$ 1.63

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	Successor Nine Months Ended September 30, 2017	Period September 1 through September 30, 2016	Predecessor Period January 1 through August 31, 2016
Production revenues (in thousands):⁽¹⁾			
Eagle Ford:			
Natural gas revenue	\$ 504	\$ 35	\$ 298
Oil revenue	27,253	1,306	14,622
Natural gas liquids revenue	701	45	305
Total revenues	\$ 28,458	\$ 1,386	\$ 15,225
Coal-bed Methane:			
Natural gas revenue	\$ 83,342	\$ 9,628	\$ 69,358
Oil revenue			
Natural gas liquids revenue			
Total revenues	\$ 83,342	\$ 9,628	\$ 69,358
Utica / Indiana:			
Natural gas revenue	\$ 3,213	\$ 339	\$ 2,520
Oil revenue	301	50	392
Natural gas liquids revenue	94	7	56
Total revenues	\$ 3,608	\$ 396	\$ 2,968
Mid-Continent			
Natural gas revenue	\$ 18,182	\$ 2,165	\$ 11,188
Oil revenue	2,820	362	1,839
Natural gas liquids revenue	5,788	609	4,010
Total revenues	\$ 26,790	\$ 3,136	\$ 17,037
Rangely: ⁽⁷⁾			
Natural gas revenue	\$	\$	\$
Oil revenue	20,501	2,843	23,883
Natural gas liquids revenue	1,516	214	1,557
Total revenues	\$ 22,017	\$ 3,057	\$ 25,440
Total production revenues:			
Natural gas revenue	\$ 105,241	\$ 12,167	\$ 83,364
Oil revenue	50,875	4,561	40,736
Natural gas liquids revenue	8,099	875	5,928
Subordinated revenue ⁽²⁾	(3,285)	(342)	(951)

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Total revenues	\$ 160,930	\$ 17,261	\$ 129,077
Average sales price:			
Natural gas (per Mcf): ⁽³⁾			
Total realized price, after hedge ⁽⁴⁾ (1)	\$ 2.70	\$ 2.70	\$ 3.39
Total realized price, before hedge ⁽⁴⁾	\$ 2.71	\$ 2.61	\$ 1.96
Oil (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 44.90	\$ 39.92	\$ 72.44
Total realized price, before hedge	\$ 46.76	\$ 42.21	\$ 36.94
Natural gas liquids (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 19.32	\$ 16.30	\$ 13.55
Total realized price, before hedge	\$ 19.32	\$ 16.30	\$ 13.55
Production costs (per Mcfe): ⁽³⁾			
Eagle Ford:			
Lease operating expenses	\$ 1.17	\$ 2.03	\$ 1.71
Production taxes	0.44	0.49	0.43
Transportation and compression	0.07	0.14	0.13
	\$ 1.68	\$ 2.66	\$ 2.27

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	Successor Nine Months Ended September 2017	Period September 1 through September 30, 2016	Predecessor Period January 1 through August 31, 2016
Coal-bed Methane:			
Lease operating expenses	\$ 1.03	\$ 1.06	\$ 1.00
Production taxes	0.23	0.24	0.17
Transportation and compression	0.12	0.19	0.25
	\$ 1.39	\$ 1.48	\$ 1.43
Utica / Indiana:			
Lease operating expenses	\$ 0.47	\$ 0.46	\$ 0.38
Production taxes	0.11	0.06	0.06
Transportation and compression	0.11	0.12	0.11
	\$ 0.69	\$ 0.65	\$ 0.55
Mid-Continent:			
Lease operating expenses	\$ 0.93	\$ 0.99	\$ 0.96
Production taxes	0.15	0.20	0.17
Transportation and compression	0.13	0.23	0.25
	\$ 1.21	\$ 1.42	\$ 1.38
Rangely: ⁽⁷⁾			
Lease operating expenses	\$ 4.76	\$ 4.59	\$ 4.33
Production taxes	0.48	0.62	0.59
Transportation and compression	0.01	0.01	0.01
	\$ 5.24	\$ 5.22	\$ 4.92
Total production costs:			
Lease operating expenses ⁽⁵⁾	\$ 1.23	\$ 1.34	\$ 1.27
Production taxes	0.24	0.27	0.12
Transportation and compression	0.11	0.18	0.22
	\$ 1.58	\$ 1.79	\$ 1.61

- (1) For the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016, production revenue includes the portion of settlements associated with gains and losses on commodity derivative contracts previously recognized within accumulated other comprehensive income following our Predecessor's decision to de-designate hedges beginning on January 1, 2015, consisting of \$1.5 million for natural gas for the Predecessor period from July 1, 2016 through August 31, 2016, and \$2.3 million for natural gas and

- \$8.1 million for oil for the Predecessor period from January 1, 2016 through August 31, 2016.
- (2) Represents the amount of subordination of our production revenue to investor partners within certain of our Drilling Partnerships. In addition to recognizing subordinated revenues, we also subordinate a corresponding proportionate share of subordinated lease operating expenses to investor partners within certain of our Drilling Partnerships, which lowers our overall production costs. The corresponding subordinated lease operating expenses for the Successor three and nine months ended September 30, 2017 and period from September 1 through September 30, 2016 were \$0.7 million, \$1.6 million and \$0.1 million, respectively, and for the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 were \$0.3 million and \$0.6 million, respectively.
 - (3) Mcf represents thousand cubic feet; Mcfe represents thousand cubic feet equivalents; and Bbl represents barrels.
 - (4) For the Successor three months and nine months ended September 30, 2017, and period from September 1, 2016 through September 30, 2016, calculation includes the impact of cash settlements on commodity derivative contracts, consisting of \$1.8 million in receipts for natural gas derivative contracts and \$0.1 million in payments for crude oil derivative contracts for the Successor three months ended September 30, 2017, \$0.5 million in payments for natural gas derivative contracts and \$1.8 million in payments for crude oil derivative contracts for the Successor nine months ended September 30, 2017, and \$0.4 million in receipts for natural gas derivative contracts and \$0.2 million in payments for crude oil derivative contracts for the Successor period from September 1, 2016 through September 30, 2016. For the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016, calculation includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our Predecessor's decision to de-designate hedges beginning on January 1, 2015, consisting of \$3.6 million and \$54.2 million in receipts associated with natural gas derivative contracts and \$0.1 million in payments and \$26.4 million in receipts associated with crude oil derivative contracts.
 - (5) Calculation excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effect of this subordination, the average realized gas sales price was \$2.64 per Mcf (\$2.49 per Mcf before the effects of financial hedging), \$2.78 per Mcf (\$2.62 per Mcf before the effects of financial hedging), \$2.63 per Mcf (\$2.53 per Mcf before the effects of financial hedging), \$3.00 per Mcf (\$2.47 per Mcf before the effects of financial hedging) and \$3.37 per Mcf (\$1.94 per Mcf before the effects of financial hedging) for the Successor three months ended September 30, 2017, the nine months ended September 30, 2017 and the period from September 1, 2016 through September 30, 2016 and for the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016, respectively.
 - (6) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effects of these costs, total lease operating expenses per Mcfe were \$1.10 per Mcfe (\$1.41 per Mcfe for total production costs), \$1.20 per Mcfe (\$1.55 per Mcfe for total production costs), \$1.32 per Mcfe (\$1.76 per Mcfe for total production costs), \$1.18 per Mcfe (\$1.61 per Mcfe for total production costs) and \$1.25 per Mcfe (\$1.60 per Mcfe for total production costs) for the Successor periods three months ended September 30, 2017, nine months ended September 30, 2017, and the period from September 1, 2016 through September 30, 2016 and the Predecessor periods from July 1, 2016 through January 31, 2016 and from January 1, 2016 through August 31, 2016, respectively.
 - (7) We sold our interest in Rangely on August 7, 2017 (see Recent Developments).

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	Successor Period Three Months Ended September 30, 2017	September 1 through September 30, 2016	Predecessor Period July 1 through August 31, 2016
(in thousands)			
Gas and oil production revenues	\$ 47,424	\$ 17,261	\$ 36,290
Gas and oil production costs	\$ (21,633)	\$ (9,854)	\$ (18,577)

	Successor Period Nine Months Ended September 30, 2017	September 1 through September 30, 2016	Predecessor Period January 1 through August 31, 2016
(in thousands)			
Gas and oil production revenues	\$ 160,930	\$ 17,261	\$ 129,077
Gas and oil production costs	\$ (74,355)	\$ (9,854)	\$ (80,988)

Our gas and oil production revenues were lower during in the current quarter than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from July 1, 2016 through August 31, 2016 due to decreases in production volumes at our operating areas due to natural declines and cost control operating decisions and the sale of our interests in Rangely, partially offset by an increase in volumes at our Eagle Ford operating area due to 15 wells turned inline since the end of the third quarter 2016 and higher average realized sales prices before hedging activities resulting from the improved commodity pricing environment.

Our gas and oil production revenues were higher in the nine months ended September 30, 2017 than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 due to higher average realized sales prices before hedging activities resulting from the improved commodity pricing environment and an increase in volumes at our Eagle Ford operating area due to 15 wells turned inline since the end of the third quarter 2016, partially offset by decreases in production volumes at our operating areas due to natural declines and cost control operating decisions and the sale of our interests in Rangely.

Our total production costs were lower in the current quarter than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from July 1, 2016 through August 31, 2016 primarily due to a decrease in lease operating expenses related to lower labor costs from employee reductions and other production cost control measures in each of our operating areas, a decrease in transportation costs due to contract negotiations for lower rates, a decrease in property taxes, and the sale of our interests in Rangely.

Our total production costs were lower in the nine months ended September 30, 2017 than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 primarily due to a decrease in lease operating expenses related to lower labor costs from employee reductions and other production cost control measures in each of our operating areas, a decrease in transportation costs due to contract negotiations for lower rates, and the sale of our interests in Rangely; partially offset by an increase in production taxes due to higher realized sales prices.

DRILLING PARTNERSHIP MANAGEMENT

We sponsored and continue to manage tax-advantaged investment partnerships (the "Drilling Partnerships"), in which we coinvested, to finance a portion of our natural gas, crude oil and NGL production activities and generated revenues as the manager and operator of the Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenues and a portion of administration and oversight revenues. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we recognize a current liability titled "Liabilities Associated with Drilling Contracts" on our condensed consolidated balance sheet. After the Drilling Partnership well is completed and turned in line, we are entitled to receive additional well services and operating fee revenues, administration and oversight fee revenues, and gathering and processing fee revenues on a monthly basis while the well is operating and as the services are performed.

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In addition, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 10-30%, which is recognized in our gas and oil production segment.

	Successor Period Three Months Ended September 30, 2017		September 1 through September 30, 2016	Predecessor Period July 1 through August 31, 2016	
<i>(in thousands)</i>					
Drilling partnership management revenues	\$ 1,997	\$	2,074	\$	18,778
Drilling partnership management expenses	248		1,266		16,121

	Successor Period Nine Months Ended September 30, 2017		September 1 Through September 30, 2016	Predecessor Period January 1 through August 31, 2016	
<i>(in thousands)</i>					
Drilling partnership management revenues	\$ 17,387	\$	2,074	\$	24,446
Drilling partnership management expenses	10,026		1,266		17,427

Drilling partnership management revenues. Our Drilling partnership management revenues were lower in the current quarter and in the nine months ended September 30, 2017 compared to each of our Successor period from September 1, 2016 and the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 primarily due to a decrease in well construction and completion revenues related to the timing of drilling and completion activities for the partnership wells, which are recognized on a cost plus basis.

Drilling partnership management expenses. Our drilling partnership management expenses were lower in the current quarter and in the nine months ended September 30, 2017 compared to each of our Successor period from September 1, 2016 and the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 due to a decrease in well construction and completion expenses related to the timing of drilling and completion activities for the partnership wells, which are recognized on a percentage of completion basis.

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	Successor Period from Three Months Ended September 30, 2017	September 1, 2016 through September 30, 2016	Predecessor Period from July 1, 2016 through August 31, 2016
(in thousands)			
<u>Other Revenues</u>			
Gain (loss) on mark-to-market derivatives	\$ (4,068)	\$ (2,079)	\$ 2,353
<u>Other Expenses</u>			
General and administrative	\$ 10,142	\$ 4,530	\$ 5,128
Depreciation, depletion and amortization	11,934	5,152	20,585
Loss on divestiture	(5,177)		
Interest expense	15,268	3,470	14,087
Gain (loss) on asset sales and disposal	(82)	5	(18)
Reorganization items, net		353	16,614
Other income (loss)	(777)		(3,063)
Income tax benefit	(202)		

	Successor Period from Nine Months Ended September 30, 2017	September 1, 2016 through September 30, 2016	Predecessor Period from January 1, 2016 through August 31, 2016
(in thousands)			
<u>Other Revenues</u>			
Gain (loss) on mark-to-market derivatives	\$ 36,925	\$ (2,079)	\$ (23,248)
<u>Other Expenses</u>			
General and administrative	\$ 32,961	\$ 4,530	\$ 41,038
Depreciation, depletion and amortization	38,402	5,152	73,272
Loss on divestiture	(43,369)		
Interest expense	41,816	3,470	71,059
Gain (loss) on asset sales and disposal	25	5	(551)
Gain on extinguishment of debt			26,498
Reorganization items, net		353	16,614
Other income (loss)	(925)		(3,063)
Income tax benefit	(11,503)		

Gain (Loss) on Mark-to-Market Derivatives. We recognize changes in the fair value of our derivatives immediately within gain (loss) on mark-to-market derivatives on our condensed consolidated statements of operations. The gains on mark-to-market derivatives during the Successor nine months ended September 30, 2017 and the Predecessor

period from July 1, 2016 through August 31, 2016 were due to decreases in commodity future prices relative to our derivative positions as of the respective prior period end. The losses on mark-to-market derivatives during the Successor three months ended September 30, 2017, the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 were due to increases in commodity future prices relative to our Successor's and our Predecessor's derivative positions as of the respective prior period end.

General and Administrative. General and administrative expenses during the three months ended September 30, 2017 as compared to the Predecessor period from July 1, 2016 through August 31, 2016 and the Successor period from September 1, 2016 through September 30, 2016 reflect increases in non-recurring transaction costs and salaries, wages and benefits, partially offset by decreases in stock compensation, syndication expense, and other corporate activities.

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General and administrative expenses during the nine months ended September 30, 2017 as compared to the Predecessor period from January 1, 2016 through August 31, 2016 and the Successor period from September 1, 2016 through September 30, 2016 reflect decreases in non-recurring transaction costs, salaries, wages and benefits, syndication expense, and other corporate activities.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization expenses decreased in the current quarter as compared to the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from July 1, 2016 through August 31, 2016 due to the application of fresh-start accounting to our proved properties on September 1, 2016, which reduced the depletable cost basis of our proved gas and oil properties resulting in lower depletion expense, lower production volumes, and the sale of our interests in Rangely.

Our depreciation, depletion and amortization expenses were lower in the nine months ended September 30, 2017 as compared to the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 due to the application of fresh-start accounting to our proved properties on September 1, 2016, which reduced the depletable cost basis of our proved gas and oil properties resulting in lower depletion expense, lower production volumes, and the sale of our interests in Rangely.

Loss on Divestiture. We determined that the carrying value of the Rangely Assets exceeded the fair value less costs to sell, which resulted in an impairment of \$38.2 million recognized in loss on divestiture on our condensed consolidated statement of operations during the nine months ended September 30, 2017. We recognized a \$5.2 million loss on asset sale from the closing of the Rangely Assets sales during the Successor three and nine months ended September 30, 2017 resulting from final negotiations and settlement of working capital adjustments in connection with the preliminary purchase price adjustments.

Interest Expense. Interest expense during the Successor three months ended September 30, 2017 primarily consisted of \$10.1 million related to our Second Lien Credit Facility, \$4.0 million related to our First Lien Credit Facility, and \$1.4 million related to amortization of deferred financing costs, partially offset by \$0.2 million in capitalized interest. Interest expense during the Successor period from September 1, 2016 through September 30, 2016 consisted of \$2.5 million related to our Second Lien Credit Facility, \$1.5 million related to our First Lien Credit Facility and \$0.1 million related to amortization of deferred financing costs, partially offset by \$0.6 million in capitalized interest. Interest expense during the Predecessor period from July 1, 2016 through August 31, 2016 consisted of \$4.8 million related to our Predecessor's second lien term loan, \$4.1 million related to our Predecessor's senior notes, \$3.6 million related to our Predecessor's first lien credit facility and \$3.3 million related to amortization of deferred financing costs and debt discounts, partially offset by \$1.7 million in capitalized interest.

Interest expense during the Successor nine months ended September 30, 2017 primarily consisted of \$26.6 million related to our Second Lien Credit Facility, \$13.1 million related to our First Lien Credit Facility, and \$2.5 million related to amortization of deferred financing costs, partially offset by \$0.4 million in capitalized interest. Interest expense during the Successor period from September 1, 2016 through September 30, 2016 consisted of \$2.5 million related to our Second Lien Credit Facility, \$1.5 million related to our First Lien Credit Facility and \$0.1 million related to amortization of deferred financing costs, partially offset by \$0.6 million in capitalized interest. Interest expense during the Predecessor period from January 1, 2016 through August 31, 2016 consisted of \$32.6 million related to our Predecessor's senior notes, \$17.4 million related to our Predecessor's second lien term loan, \$14.5 million related to amortization of deferred financing costs and debt discounts and \$13.1 million related to our Predecessor's first lien credit facility, partially offset by \$6.5 million in capitalized interest.

Gain on Early Extinguishment of Debt. The gain on early extinguishment of debt for the Predecessor period from January 1, 2016 through August 31, 2016 represents a \$26.5 million gain related to the repurchase of a portion of our

Predecessor's senior notes. Of the \$26.5 million gain, \$27.4 million related to the gain from the redemption of the principal values and accrued interest, partially offset by \$0.9 million related to the accelerated amortization of the related deferred financing costs.

Reorganization Items, Net. Incremental costs incurred as a result of the Chapter 11 Filings, net gain on settlement of liabilities subject to compromise and reorganization adjustments, and net impact of fresh start adjustments are classified as Reorganization items, net in the Predecessor's condensed consolidated statement of operations. The following table summarizes the reorganization items:

Professional fees and other	\$ (33,065)
Accelerated amortization of deferred financing costs	(9,565)
Net gain on reorganization adjustments	361,479
Net loss on fresh start adjustments	(335,463)
Total reorganization items, net	\$ (16,614)

Other income (loss). The \$0.8 million loss for the Successor three months ended September 30, 2017, includes a \$1.3 million adjustment to net realizable value related to a settled escrow account receivable, partially offset by \$0.6 million in transition service

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agreement fees related to the Appalachian Assets sale. The \$0.9 million loss for the Successor nine months ended September 30, 2017, represents a \$1.3 million adjustment to net realizable value related to a settled escrow account and the \$0.6 million write-off of promotional items, partially offset by \$0.6 million in transition service agreement fees related to the Appalachian Assets sale and \$0.4 million sales tax refund for equipment purchased for our Texas operations. The \$3.0 million loss for the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 represent non-cash losses for the write-off of notes receivables with certain investors of our Drilling Partnerships.

Income Tax Provision (Benefit). For the Successor nine months ended September 30, 2017, we recorded a full valuation allowance against our net deferred tax asset balance, which reduced our effective tax rate to 0.74%. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. Our effective t