Titan Energy, LLC
Form 10-Q
August 21, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 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	90-0812516
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
425 Houston Street, Suite 300	
Fort Worth, TX	76102

(Address of principal executive offices) (Zip code)

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

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 August 17, 2017 was 5,469,798.

TITAN ENERGY, LLC

INDEX TO QUARTERLY REPORT

ON FORM 10-Q

TABLE OF CONTENTS

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,” “m “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 ability to satisfy covenants in our debt documents;
- 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.

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

3

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.

PART I: FINANCIAL INFORMATION

ITEM 1: FINANCIAL STATEMENTS

TITAN ENERGY, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	June 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	16,247	$24,446
Accounts receivable	20,908	26,472
Advances to affiliates	6,486	4,145
Subscriptions receivable	—	5,656
Prepaid expenses and other	12,578	17,108
Current assets held for sale (Note 3)	124,657	8,271
Total current assets	180,876	86,098
Property, plant and equipment, net	538,418	670,769
Long-term derivative asset	1,606	—
Other assets, net	7,250	10,562
Non-current assets held for sale (Note 3)	—	114,405
Total assets	$728,150	$881,834
LIABILITIES AND MEMBERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$25,454	$27,647
Liabilities associated with drilling contracts	—	10,656
Current portion of derivative liability	890	30,519
Accrued well drilling and completion costs	6,044	4,933
Accrued interest	1,287	1,503
Accrued liabilities	15,266	17,171
Current portion of long-term debt	643,378	694,810
Current liabilities held for sale (Note 3)	2,296	9,461
Total current liabilities	694,615	796,700
Long-term derivative liability	1	13,208
Asset retirement obligations	14,486	15,031
Other long-term liabilities	1,628	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)	323	(145)
Common shareholders' equity (deficit)	17,097	(6,796)
Total members' equity (deficit)	17,420	(6,941)
Total liabilities and members' equity (deficit)	$728,150	$881,834

See accompanying notes to condensed consolidated financial statements.

TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30, 2017	2016	June 30, 2017	2016
Revenues:				
Gas and oil production	$53,939	$47,527	$113,506	$92,787
Drilling partnership management	7,610	748	15,390	5,668
Gain (loss) on mark-to-market derivatives	14,788	(67,162)	40,993	(25,601)
Total revenues	76,337	(18,887)	169,889	72,854
Costs and expenses:				
Gas and oil production	25,077	29,188	52,722	62,411
Drilling partnership management	5,310	(837)	9,778	1,306
General and administrative	10,929	20,934	22,819	36,808
Depreciation, depletion and amortization	12,806	25,311	26,468	52,687
Loss on divestiture	38,192	—	38,192	—
Total costs and expenses	92,314	74,596	149,979	153,212
Operating income (loss)	(15,977)	(93,483)	19,910	(80,358)
Interest expense	(13,615)	(30,545)	(26,548)	(56,972)
Gain on early extinguishment of debt	—	—	—	26,498
Other income (loss)	(181)	(543)	(41)	(533)
Loss from continuing operations before income taxes	(29,773)	(124,571)	(6,679)	(111,365)
Income tax provision (benefit)	(9,653)	—	(11,301)	—
Net income (loss) from continuing operations	(20,120)	(124,571)	4,622	(111,365)
Net income (loss) from discontinued operations	16,628	(16,998)	18,789	(17,441)
Net income (loss)	(3,492)	(141,569)	23,411	(128,806)
Preferred limited partner dividends	—	(365)	—	(4,013)
Net income (loss) attributable to common shareholders and Series A preferred member	$(3,492)	$—	$23,411	$—
Net loss attributable to common limited partners and the general partner	—	(141,934)	—	(132,819)
Allocation of net income (loss) attributable to :				
Series A Preferred member	(70)	—	468	—
Common shareholders	(3,422)	—	22,943	—
Common limited partners' interest	$—	$(139,096)	$—	$(130,163)
General partner's interest	—	(2,838)	—	(2,656)
Net income (loss) attributable to common shareholders per share / common limited partners per unit (Note 2):				

Basic income (loss) continuing operations	$(3.81)	$(1.20)	$0.88	$(1.10)
Diluted income (loss) continuing operations	$(3.81)	$(1.20)	$0.83	$(1.10)
Basic income (loss) from discontinued operations	$3.15	$(0.16)	$3.56	$(0.17)
Diluted income (loss) from discontinued operations	$3.15	$(0.16)	$3.37	$(0.17)
Weighted average common limited partner units outstanding (Note 2):				
Basic	5,181	102,430	5,175	102,416
Diluted	5,181	102,430	5,467	102,416

See accompanying notes to condensed consolidated financial statements.

TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Net income (loss)	$(3,492)	$(141,569)	$23,411	$(128,806)
Other comprehensive loss:				
Derivative instruments designated as cash flow hedges:				
Reclassification to net income (loss) of mark-to-market gains	—	(5,555)	—	(9,070)
Total other comprehensive loss	—	(5,555)	—	(9,070)
Comprehensive income (loss) attributable to Series A Preferred member and common shareholders	$(3,492)	$—	23,411	—
Comprehensive loss attributable to common and preferred limited partners and the general partner	$—	$(147,124)	$—	$(137,876)

See accompanying notes to condensed consolidated financial statements.

TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN MEMBERS' EQUITY (DEFICIT)

(in thousands, except unit data)

(Unaudited)

	Series A Preferred Member's 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	—	—	22,011	950	950
Net income	—	468	—	22,943	23,411
Balance at June 30, 2017	1	$ 323	5,469,798	$ 17,097	$ 17,420

See accompanying notes to condensed consolidated financial statements.

TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Successor	Predecessor
	Six Months Ended June 30,	
	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$23,411	$(128,806)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Net (income) loss from discontinued operations	(18,789)	17,441
Depreciation, depletion and amortization	26,468	52,687
Loss on divestiture	38,192	—
(Gain) loss on derivatives	(29,470)	34,731
(Gain) on extinguishment of debt	—	(26,498)
Other loss	452	533
Non-cash compensation expense	950	(298)
Non-cash interest expense	13,911	—
Deferred income taxes (benefit)	(11,301)	—
Amortization of deferred financing costs and debt discount	1,303	9,127
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	(11,015)	76,419
Accounts payable and accrued liabilities	(14,046)	(51,980)
Net cash provided by (used in) continuing operating activities	20,066	(16,644)
Net cash provided by discontinued operating activities	4,189	(665)
Net cash provided by (used in) operating activities	24,255	(17,309)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(32,635)	(18,820)
Net cash used in continuing investing activities	(32,635)	(18,820)
Net cash provided by discontinued investing activities	66,629	—
Net cash provided by (used in) investing activities	33,994	(18,820)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under revolving credit facility	—	135,000
Repayments under revolving credit facility	(65,609)	(57,500)
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	(839)	(564)
Net cash provided by (used in) financing activities	(66,448)	59,034
Net change in cash and cash equivalents	(8,199)	22,905
Cash and cash equivalents, beginning of period	24,446	1,353

Cash and cash equivalents, end of period	$16,247	$24,258

See accompanying notes to condensed consolidated financial statements.

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. We sponsor and manage tax-advantaged investment partnerships (the "Drilling Partnerships"), in which we coinvest, to finance a portion of our natural gas, crude oil and NGL production activities. 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, LLC 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 June 30, 2017, we had 5,469,798 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.

- 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.

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. Sustained low commodity prices could have a material and adverse effect on our liquidity position. In addition, since the Plan Effective Date, our ability to raise capital through our Drilling Partnerships has been challenged. The decline in the fee-income generated from our Drilling Partnerships business has negatively impacted our ability to remain in compliance with the covenants under our credit facilities.

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 $643.4 million of outstanding indebtedness under our credit facilities, which is net of $1.8 million of deferred financing costs, as current portion of long term debt, net within our condensed consolidated balance sheet as of June 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. The amendment provides 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 amendment.

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 are 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.

Even following this amendment, 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.

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 are 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. We expect to complete the remainder of the Appalachia Assets sale for additional cash proceeds of approximately $11.4 million by September 2017, which will be used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

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 CO_2 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 CO_2 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, subject to 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.

We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, 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.

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.

Income Taxes

Our effective tax rate for the Successor three and six months ended June 30, 2017 was 0.6% and 1.14%, respectively, which represents 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 six months ended June 30, 2017, we recognized a provision for income taxes of $9.7 million and $11.6 million, respectively, in net income (loss) from discontinued operations on our condensed consolidated statement of operations. For the Successor three and six months ended June 30, 2017, we recognized a corresponding income tax benefit of $9.7 million and $11.6 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.

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 three and six months ended June 30, 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.

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.

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 June 30, 2017	Six Months Ended June 30, 2017
Net income (loss) from continuing operations	$ (20,120)	$ 4,622
Less: Series A Preferred member interest in income (loss) from continuing operations	(402)	92
Net income (loss) from continuing operations utilized in the calculation of net income (loss) attributable to common shareholders per share	$ (19,718)	$ 4,530
Net income from discontinued operations	$ 16,628	$ 18,789
Less: Series A Preferred member interest in net income from discontinued operations	332	376
Net income from discontinued operations utilized in the calculation of net income attributable to common shareholders per share	$ 16,296	$ 18,413

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 June 30, 2017	Six Months Ended June 30, 2017
Weighted average number of common shares - basic (1)	5,181	5,175
Add dilutive effect of share based awards at end of period (2)	—	292
Weighted average number of common shares - diluted	5,181	5,467

(1) For each period presented, 278,000 restricted common shares outstanding were excluded from the 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 the three months ended June 30, 2017 resulted in net loss from continuing operations attributable to common shareholders, potentially dilutive shares were excluded because their inclusion would have been anti-dilutive.

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 thousand):

	Predecessor Three Months ended June 30, 2016	Six Months Ended June 30, 2016
Net loss from continuing operations	$ (124,571)	$ (111,365)
Preferred limited partner dividends	(365)	(4,013)
Net loss from continuing operations attributable to common limited partners and the general partner	(124,936)	(115,378)
Less: General partner's interest in net loss from continuing operations	(2,498)	(2,308)
Net loss from continuing operations attributable to common limited partners	(122,438)	(113,070)
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	(122,438)	(113,070)
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	$ (122,438)	$ (113,070)
Net loss from discontinued operations attributable to common limited partners and the general partner	$ (16,998)	$ (17,441)
Less: General partner's interest in net loss from discontinued operations	(340)	(349)
Net loss from discontinued operations attributable to common limited partners	(16,658)	(17,092)
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 partners per unit – Basic	(16,658)	(17,092)
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	$ (16,658)	$ (17,092)

(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.

16

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 Three Months Ended June 30, 2016	Six Months Ended June 30, 2016
Weighted average number of common limited partner units—basic	102,430	102,416
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	102,430	102,416

(1) For the three and six months ended June 30, 2016, 274,000 and 283,000 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 period 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 intend to adopt the new standard using the modified retrospective method, which is expected to have an immaterial impact on our financial statements. The 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. We expect to complete the remainder of the Appalachian Assets sale for additional cash proceeds of approximately $11.4 million by September 2017, which will be 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 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.

The remainder of our Appalachian Assets are classified as held for sale in our condensed consolidated balance sheet at June 30, 2017. 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 three and six months ended June 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	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Revenues:				
Gas and oil production	$9,892	$ 3,880	$20,925	$ 7,120
Drilling partnership management	4,731	4,539	7,996	8,479
Gain (loss) on mark-to-market derivatives	1,666	(6,101)	4,955	(1,542)
Other, net	702	—	—	—
Total revenues	16,991	2,318	33,876	14,057
Costs and expenses:				
Gas and oil production	$5,118	$ 1,967	$8,167	$ 4,790
Drilling partnership management	3,729	3,350	7,896	7,489
Depreciation, depletion and amortization	2,226	3,696	5,055	6,366
General and administrative	2,245	2,827	4,080	4,032
(Gain) loss on sale of assets	(28,564)	(88)	(28,602)	(22)
Impairment on assets held for sale	4,272	—	4,272	—
Interest expense	1,600	1,408	2,654	2,687
Other (income) loss	—	6,156	—	6,156
Total costs and expenses	$(9,374)	$ 19,316	$3,522	$ 31,498
Income (loss) from discontinued operations before income taxes	26,365	(16,998)	30,354	(17,441)
Income tax provision (benefit)	9,737	—	11,565	—
Net income (loss) from discontinued operations	$16,628	$ (16,998)	$18,789	$ (17,441)

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 (and expected sale) of the Appalachian Assets used to repay (and expected 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.

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, subject to customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility. The Rangely Assets were classified as held for sale in our condensed consolidated balance sheet at June 30, 2017. 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 divesture on our condensed consolidated statement of operations during the three and six months ended June 30, 2017.

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 held for sale for the periods presented, in thousands:

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Income (loss) before income taxes [1]	$(37,251)	$ (1,227)	$(34,087)	$ 8,199

(1) Income (loss) before income taxes reflects gas and oil production revenues less gas and oil production expenses, general and administrative expenses, depletion, depreciation, amortization expenses, and loss on divestitures of $38.2 million as disclosed above.

Assets Held For Sale

The following table details the major classes of assets and liabilities of the Appalachian Assets and Rangely Assets classified as held for sale for the periods presented, in thousands:

	June 30, 2017	December 31, 2016
Current assets:		
Accounts receivable	$ —	$7,254
Prepaid expenses and other	—	1,017
Property, plant and equipment, net	11,405	—
Total current assets of Appalachian Assets discontinued operations held for sale	11,405	8,271
Rangely Assets held for sale	113,252	—
Total current assets classified as held for sale	124,657	8,271
Property, plant and equipment, net	—	113,956
Other assets	—	449
Total non-current assets of Appalachian Assets discontinued operations held for sale	—	114,405
Total assets classified as held for sale	$124,657	$122,676
Current liabilities:		
Accounts payable	$—	$2,516
Current portion of derivative liability	—	4,279
Accrued liabilities and other	296	2,666
Asset retirement obligations	593	—
Other long-term liabilities	368	—
Total current liabilities of Appalachian Assets discontinued operations held for sale	1,257	9,461
Rangely Assets held for sale	1,039	—
Total current liabilities classified as held for sale	2,296	9,461
Long-term derivative liability	—	1,407
Asset retirement obligations	—	60,316
Other long-term liabilities	—	682
Total non-current liabilities of Appalachian Assets discontinued operations held for sale	—	62,405
Total liabilities classified as held for sale	$2,296	$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.

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2017	December 31, 2016
Natural gas and oil properties:		
Proved properties	$518,886	$608,901
Unproved properties	52,767	73,057
Support equipment and other	8,376	8,081
Total natural gas and oil properties	580,029	690,039
Less – accumulated depreciation, depletion and amortization	(41,611)	(19,270)
Total property, plant and equipment, net	$538,418	$670,769

During the Successor six months ended June 30, 2017 and the Predecessor six months ended June 30, 2016, we recognized $1.2 million and $15.5 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 months ended June 30, 2017 and the Predecessor three months ended June 30, 2016, was 8.0% and 6.6%, respectively. The aggregate amount of interest capitalized during the Successor three months ended June 30, 2017 and the Predecessor three months ended June 30, 2016 was $0.2 million and $2.4 million, respectively. The weighted average interest rate used to capitalize interest on borrowed funds during the Successor six months ended June 30, 2017 and the Predecessor six months ended June 30, 2016, was 7.8% and 6.7%, respectively The aggregate amount of interest capitalized by us was $0.2 million and $4.8 million for the Successor six months ended June 30, 2017 and the Predecessor six months ended June 30, 2016, respectively.

For the Successor three months ended June 30, 2017 and the Predecessor three months ended June 30, 2016, we recorded $0.4 million and $0.7 million, respectively, of accretion expense related to our and our Predecessor’s asset retirement obligations within depreciation, depletion and amortization in our and our Predecessor’s condensed consolidated statements of operations. For the Successor six months ended June 30, 2017 and the Predecessor six months ended June 30, 2016, we recorded $0.7 million and $1.4 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):

	June 30, 2017	December 31, 2016
First Lien Credit Facility	$370,200	$435,809
Second Lien Credit Facility	274,933	261,022
Deferred financing costs, net of accumulated amortization of $505 and $172, respectively	(1,755)	(2,021)
Total debt, net	643,378	694,810
Less current maturities	(643,378)	(694,810)
Total long-term debt, net	$—	$—

Cash Interest. Total cash payments for interest for the Successor three months ended June 30, 2017, and the Predecessor three months ended June 30, 2016, were $7.1 million and $12.5 million, respectively. Total cash payments for interest for the Successor six months ended June 30, 2017, and the Predecessor six months ended June 30, 2016, were $13.9 million and $53.7 million, respectively.

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:

- 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 June 30, 2017, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 5.0%.
- 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 (the "First Lien Credit Facility Amendment") to the First Lien Credit Facility with Wells Fargo, as administrative agent, and the lenders party thereto. Pursuant to the First Lien Credit Facility 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 are 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 First Lien Credit Facility Amendment confirms the conforming and non-conforming tranches of the borrowing base at $410 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 $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 will be required to be reduced to $10 million by November 1, 2017. In addition, we will be 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, subject to 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.

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:

- 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 will use 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 are 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.

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.

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	Successor	Predecessor
	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets[1]	$—	$ 5,477	$—	$ 8,926
Portion of settlements attributable to subsequent mark- to-market gains (losses)	(678)	35,805	(3,975)	77,164
Total cash settlements on commodity derivative contracts	$(678)	$ 41,282	$(3,975)	$ 86,090
Gains (losses) recognized on cash settlement[2]	$1,236	$ (2,291)	$11,523	$ 9,130
Gains (losses) recognized on open derivative contracts[2]	13,552	(64,871)	29,470	(34,731)
Gains (losses) on mark-to-market derivatives	$14,788	$ (67,162)	$40,993	$ (25,601)

(1) Recognized in gas and oil production revenue.
(2) Recognized in gain (loss) on mark-to-market derivatives.

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):

Offsetting Derivatives as of June 30, 2017	Gross Amounts Recognized	Gross Amounts Offset	Net Amount Presented
Current portion of derivative assets	$ 4,213	$ (3,688)	$ 525
Long-term portion of derivative assets	1,898	(292)	1,606
Total derivative assets	$ 6,111	$ (3,980)	$ 2,131
Current portion of derivative liabilities	$ (4,578)	$ 3,688	$ (890)
Long-term portion of derivative liabilities	(293)	292	(1)
Total derivative liabilities	$ (4,871)	$ 3,980	$ (891)
Offsetting Derivatives as of December 31, 2016			
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)

23

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

Type	Production Period Ending December 31,	Volumes[(1)]		Average Fixed Price[(2)]	Fair Value Asset / (Liability) (in thousands)[(2)]	Total Type (in thousands)
Natural Gas – Fixed Price Swaps	2017	25,839,800	(3)	$ 3.140	$ 1,116	
	2018	43,947,300		$ 2.959	$ (1,465)	
						$ (349)
Crude Oil – Fixed Price Swaps	2017	392,900	(3)	$ 47.441	$ 383	
	2018	588,200		$ 50.284	$ 1,206	
						$ 1,589
					Total net asset	$ 1,240

(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 six months of 2017 beginning July 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 June 30, 2017 and December 31, 2016, all of our derivative financial instruments were classified as Level 2.

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

Derivatives, Fair Value, as of June 30, 2017	Level 1	Level 2	Level 3	Total
Assets, gross				
Commodity swaps	$ —	$6,111	$ —	$6,111
Total derivative assets, gross	—	6,111	—	6,111
Liabilities, gross				

Commodity swaps		—	(4,871)		—	(4,871)
Total derivative liabilities, gross		—	(4,871)		—	(4,871)
Total derivatives, fair value, net	$	—	$1,240	$	—	$1,240

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 June 30, 2017, which consists of our First Lien Credit Facility and Second Lien Credit Facility, approximated carrying value of $645.1 million. At June 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 as of June 30, 2017 (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.

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 June 30, 2017 and December 31, 2016, we had receivables of $6.3 million and $3.3 million, respectively, from ATLS related to the timing of funding cash accounts related to general and administrative expenses, such as payroll and benefits, which was recorded 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 quarter ended June 30, 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 $6.2 million, net of consolidation and transfer adjustments, for the three and six months ended June 30, 2016, which was recorded in net income (loss) from discontinued operations in the condensed consolidated statements of operations.

As of each of June 30, 2017 and 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 sheets. As of June 30, 2017 and December 31, 2016, we had trade payables of $2.7 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 June 30, 2017 and December 31, 2016, we had receivables of $0.2 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.

NOTE 9 – COMMITMENTS AND CONTINGENCIES

Drilling Partnership Commitments

As of June 30, 2017, we are committed to expend approximately $2.8 million, principally on 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 June 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 six months ended June 30, 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 six months ended June 30, 2016, our Predecessor paid a distribution of $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 six months ended June 30, 2016, our Predecessor paid a distribution of $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 $1.9 million and $0.1 million, respectively, from April 15, 2016 through June 30, 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.

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

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30, 2017	2016	June 30, 2017	2016
Gas and oil production:				
Gas and oil production revenues [1]	$68,727	$(19,635)	$154,499	$67,186
Gas and oil production costs	(25,077)	(29,188)	(52,722)	(62,411)
Depreciation, depletion and amortization	(12,494)	(22,677)	(25,809)	(47,419)
Loss on divestiture	(38,192)	—	(38,192)	—
Segment income (loss)	$(7,036)	$(71,500)	$37,776	$(42,644)
Drilling partnership management:[2]				
Drilling partnership management revenues	$7,610	$748	$15,390	$5,668
Drilling partnership management expenses	(5,310)	837	(9,778)	(1,306)
Depreciation, depletion and amortization	(312)	(2,634)	(659)	(5,268)
Segment income (loss)	$1,988	$(1,049)	$4,953	$(906)
Reconciliation of segment income (loss) to net loss:				
Segment income (loss):				
Gas and oil production	$(7,036)	$(71,500)	$37,776	$(42,644)
Drilling partnership management [2]	1,988	(1,049)	4,953	(906)
Total segment income (loss)	(5,048)	(72,549)	42,729	(43,550)
General and administrative expenses [3]	(10,929)	(20,934)	(22,819)	(36,808)
Interest expense[3]	(13,615)	(30,545)	(26,548)	(56,972)
Gain on early extinguishment of debt [3]	—	—	—	26,498
Other income (loss) [3]	(181)	(543)	(41)	(533)
Income tax (provision) benefit [3]	9,653	—	11,301	—
Net income (loss) from continuing operations	(20,120)	(124,571)	4,622	(111,365)

Reconciliation of segment revenues to total revenues:				
Gas and oil production	$68,727	$(19,635)	$154,499	$ 67,186
Drilling partnership management	7,610	748	15,390	5,668
Total revenues	$76,337	$(18,887)	$169,889	$ 72,854
Capital expenditures:				
Gas and oil production	$21,999	$5,210	$31,912	$ 17,155
Drilling partnership management	101	416	521	1,550
Corporate and other	91	24	202	115
Total capital expenditures	$22,191	$5,650	$32,635	$ 18,820

(1) Includes gain (loss) on mark-to-market derivatives. For the Predecessor three months ended June 30, 2016, a $67.2 million loss on mark-to-market derivatives is included 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 & administrative expenses, interest expense, gain on early extinguishment of debt, 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.

	June 30, 2017	December 31, 2016
Balance sheet:		
Total assets:		
Gas and oil production	$564,464	$703,243
Drilling partnership management	5,598	11,786
Corporate and other[1]	33,431	44,129
Assets held for sale	124,657	122,676
Total assets	$728,150	$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.

NOTE 12 – SUBSEQUENT EVENTS

Rangely Divestiture. On August 7, 2017, we completed the Rangely Asset sale for net cash proceeds of $103.5 million, subject to customary preliminary price adjustments (see Note 2).

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. We sponsor and manage tax-advantaged investment partnerships (the "Drilling Partnerships"), in which we coinvest, to finance a portion of our natural gas, crude oil and NGL production activities. 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, LLC 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 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. Sustained low commodity prices could have a material and adverse effect on our liquidity position. In addition, since the Plan Effective Date, our ability to raise capital through our Drilling Partnerships has been challenged. The decline in the fee-income generated from our Drilling Partnerships business has negatively impacted our ability to remain in compliance with the covenants under our credit facilities.

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 $643.4 million of outstanding indebtedness under our credit facilities, which is net of $1.8 million of deferred financing costs, as current portion of long term debt, net within our condensed consolidated balance sheet as of June 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. The amendment provides for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base (refer to Liquidity and Capital Resources – Credit Facilities section below 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 amendment.

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 are 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.

Even following this amendment, 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.

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 are 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.

We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, 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 "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. We expect to complete the remainder of the Appalachia Assets sale for additional cash proceeds of approximately $11.4 million by September 2017, which will be 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 CO_2 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 CO_2 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, subject to 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.

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

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 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.

At June 30, 2017, we had a one-rig program actively drilling on our Eagle Ford Shale position. We anticipate increasing to a two-rig program during the year ending December 31, 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:

32

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Gross wells drilled(3):				
Eagle Ford	—	—	4	—
Net wells drilled(1)(3):				
Eagle Ford	—	—	3	—
Gross wells turned in line(2)(3):				
Eagle Ford	4	—	4	—
Net wells turned in line(1)(2)(3):				
Eagle Ford	3	—	3	—

(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.
(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	Predecessor	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Production volumes per day:(1) (2)				
Eagle Ford:				
Natural gas (Mcfd)	584	471	626	430
Oil (Bpd)	1,988	1,188	1,998	1,275
NGLs (Bpd)	128	98	137	90
Total (Mcfed)	13,284	8,188	13,436	8,618
Coalbed Methane:				
Natural gas (Mcfd)	105,486	116,743	106,934	118,646
Oil (Bpd)	—	—	—	—
NGLs (Bpd)	—	—	—	—
Total (Mcfed)	105,486	116,743	106,934	118,646
Utica / Indiana:				
Natural gas (Mcfd)	4,156	5,561	4,290	5,954
Oil (Bpd)	19	47	29	49
NGLs (Bpd)	14	25	17	25
Total (Mcfed)	4,353	5,991	4,567	6,398
Mid-Continent:				
Natural gas (Mcfd)	30,897	36,616	31,511	39,341
Oil (Bpd)	240	385	242	469
NGLs (Bpd)	1,225	1,571	1,242	1,726
Total (Mcfed)	39,686	48,352	40,413	52,513
Rangely:(3)				
Natural gas (Mcfd)	—	—	—	—
Oil (Bpd)	1,890	2,269	2,070	2,312
NGLs (Bpd)	181	235	213	245
Total (Mcfed)	12,426	15,026	13,699	15,341
Total production volumes per day:(2)				
Natural gas (Mcfd)	141,123	159,390	143,361	164,373
Oil (Bpd)	4,137	3,889	4,339	4,104
NGLs (Bpd)	1,548	1,929	1,610	2,087
Total (Mcfed)	175,235	194,300	179,049	201,519
Total production:(2)				
Natural gas (MMcf)	12,842	14,505	25,948	29,916
Oil (MBbls)	376	354	785	747
NGLs (MBbls)	141	176	291	380
Total (MMcfe)	15,946	17,681	32,408	36,676

(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 subsequently sold our interest in Rangely on August 7, 2017 (see "Recent Developments").

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	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
Production revenues (in thousands):(1)				
Eagle Ford:				
Natural gas revenue	$163	$ 116	$ 349	$ 206
Oil revenue	8,509	6,802	17,554	12,662
Natural gas liquids revenue	179	133	448	219
Total revenues	$8,851	$ 7,051	$ 18,351	$ 13,087
Coalbed Methane:				
Natural gas revenue	$27,421	$ 22,557	$ 57,086	$ 47,281
Oil revenue	—	—	—	—
Natural gas liquids revenue	—	—	—	—
Total revenues	$27,421	$ 22,557	$ 57,086	$ 47,281
Utica / Indiana:				
Natural gas revenue	$1,096	$ 818	$ 2,293	$ 1,784
Oil revenue	79	174	235	301
Natural gas liquids revenue	25	14	75	41
Total revenues	$1,200	$ 1,006	$ 2,603	$ 2,126
Mid-Continent:				
Natural gas revenue	$5,987	$ 2,376	$ 12,366	$ 5,936
Oil revenue	992	688	2,006	1,215
Natural gas liquids revenue	1,765	1,644	3,781	2,940
Total revenues	$8,744	$ 4,708	$ 18,153	$ 10,091
Rangely: (6)				
Natural gas revenue	$—	$ —	$ —	$ —
Oil revenue	8,011	11,746	17,902	19,490
Natural gas liquids revenue	583	616	1,398	1,105
Total revenues	$8,594	$ 12,362	$ 19,300	$ 20,595
Total production revenues:(1)				
Natural gas revenue	$34,667	$ 25,867	$ 72,094	$ 55,207
Oil revenue	17,591	19,410	37,697	33,668
Natural gas liquids revenue	2,552	2,407	5,702	4,305
Subordinated revenue(2)	(881)	(157)	(1,987)	(393)
Total revenues	$53,929	$ 47,527	$ 113,506	$ 92,787
Average sales price:				

Natural gas (per Mcf):				
Total realized price, after hedge(3) (4)	$2.66	$ 3.52	$ 2.61	$ 3.50
Total realized price, before hedge(4)	$2.63	$ 1.70	$ 2.70	$ 1.78
Oil (per Bbl):				
Total realized price, after hedge(3)	$46.15	$ 84.07	$ 45.86	$ 81.84
Total realized price, before hedge	$46.72	$ 42.22	$ 48.00	$ 35.52
Natural gas liquids (per Bbl):				
Total realized price, after hedge	$18.11	$ 13.71	$ 19.57	$ 11.34
Total realized price, before hedge	$18.11	$ 13.71	$ 19.57	$ 11.34

35

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30,		Six Months Ended June 30,	
Production costs (per Mcfe):				
Eagle Ford:				
Lease operating expenses	$1.15	$ 1.74	$ 1.15	$ 1.75
Production taxes	0.48	0.47	0.46	0.42
Transportation	0.07	0.14	0.08	0.12
Total production costs (per Mcfe)	$1.70	$ 2.35	$ 1.69	$ 2.29
Coalbed Methane:				
Lease operating expenses	$1.03	$ 0.98	$ 1.01	$ 1.01
Production taxes	0.25	0.16	0.25	0.16
Transportation	0.11	0.22	0.13	0.27
Total production costs (per Mcfe)	$1.39	$ 1.36	$ 1.39	$ 1.45
Utica / Indiana:				
Lease operating expenses	$0.49	$ 0.32	$ 0.45	$ 0.39
Production taxes	0.09	0.06	0.10	0.06
Transportation	0.12	0.12	0.12	0.12
Total production costs (per Mcfe)	$0.69	$ 0.49	$ 0.67	$ 0.57
Mid-Continent:				
Lease operating expenses	$0.98	$ 0.90	$ 0.96	$ 0.99
Production taxes	0.14	0.17	0.15	0.16
Transportation	—	0.29	0.11	0.25
Total production costs (per Mcfe)	$1.12	$ 1.36	$ 1.22	$ 1.40
Rangely:(6)				
Lease operating expenses	$5.40	$ 4.37	$ 4.80	$ 4.36
Production taxes	0.57	0.60	0.54	0.58
Transportation	0.01	0.01	0.01	0.01
Total production costs (per Mcfe)	$5.98	$ 4.98	$ 5.35	$ 4.95
Total production costs:				
Lease operating expenses(5)	$1.32	$ 1.24	$ 1.28	$ 1.27
Production taxes	0.26	0.20	0.26	0.20
Transportation	0.08	0.22	0.11	0.24
Total production costs (per Mcfe)(5)	$1.66	$ 1.66	$ 1.66	$ 1.71

(1) For the Predecessor three months ended June 30, 2016 and six months ended June 30, 2016, production revenue includes the portion of settlements associated with gains 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 $26.0 million for natural gas and $9.8 million for oil for the Predecessor three months ended June 30, 2016, $50.6 million for natural gas and $26.5 million in oil for the Predecessor six months ended June 30, 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 six months ended June 30, 2017 was $0.5 million and $0.9 million, respectively, and

for the Predecessor three and six months ended June 30, 2016 was $0.1 million and $0.3 million, respectively.

(3) For the Successor three months ended June 30, 2017 and six months ended June 30, 2017, calculation includes the impact of cash settlements on commodity derivative contracts, consisting of $0.5 million in payments for natural gas derivative contracts and $0.2 million in payments for crude oil derivative contracts for the Successor three months ended June 30, 2017 and $2.3 million in payments for natural gas derivative contracts and $1.7 million in payments for crude oil derivative contracts for the Successor six months ended June 30, 2017. For the Predecessor three and six months ended June 30, 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 $26.0 million and $50.6 million in receipts associated with natural gas derivative contracts and $9.8 million and $26.5 million in receipts associated with crude oil derivative contracts.

(4) 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 $2.60 per Mcf ($2.63 per Mcf before the effects of financial hedging) for the Successor period three months ended June 30, 2017 and $3.52 per Mcf ($1.70 per Mcf before the effects of financial hedging) for the Predecessor three months ended June 30, 2016, and for the Successor six months ended June 30, 2017, the average realized gas sales price was $2.61 per Mcf ($2.70 per Mcf before the effects of financial hedging) and $3.49 per Mcf ($1.77 per Mcf before the effects of financial hedging) for the Predecessor six months ended June 30, 2016.

(5) 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 $1.29 per Mcfe ($1.63 per Mcfe for total production costs) and $1.23 per Mcfe ($1.65 per Mcfe for total production costs) for the Successor period three months ended

June 30, 2017 and the Predecessor period three months ended June 30, 2016 respectively, and for the Successor period six months ended June 30, 2017, and the Predecessor period six months ended June 30, 2016, they were $1.26 per Mcfe ($1.63 per Mcfe for total production costs) and $1.27 per Mcfe ($1.70 per Mcfe for total production costs), respectively.

(6) We subsequently sold our interest in Rangely on August 7, 2017 (see "Recent Developments").

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
(in thousands)				
Gas and oil production revenues	$53,939	$ 47,527	$113,506	$ 92,787
Gas and oil production costs	$25,077	$ 29,188	$52,722	$ 62,411

Our gas and oil production revenues were higher in the current quarter due to an increase of $10.5 million due to higher average realized sales prices before hedging activities resulting from the improved commodity pricing environment and an increase $3.1 million due to 19 wells turned inline in our Eagle Ford operating area since the end of the second quarter 2016, partially offset by an increase of $0.7 million related to subordinated revenues at our Drilling Partnerships and a decrease of $6.5 million due to lower production volumes resulting from natural decline and cost control operating decisions.

Our gas and oil production revenues were higher in the six months ended June 30, 2017, due to an increase of $31.6 million due to higher average realized sales prices before hedging activities resulting from the improved commodity pricing environment and an increase of $2.4 million due to 19 wells turned inline in our Eagle Ford operating area since the end of the second quarter 2016, partially offset by an increase of $1.6 million related to subordinated revenues at our Drilling Partnerships and a decrease of $11.7 million due to lower production volumes resulting from natural decline and cost control operating decisions.

Our total production costs were lower in the current quarter due to a $1.4 million 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 and a $3.4 million decrease in transportation costs due to contract negotiations for lower rates, partially offset by a $0.7 million increase in production taxes due to higher realized sales prices.

Our total production costs were lower in the six months ended June 30, 2017, due to a $5.8 million decrease in lease operating expenses related to lower labor costs from employee reductions and other production cost control measures in each of our operating area and a $5.0 million decrease in transportation costs due to contract negotiations for lower rates, partially offset by a $1.2 million increase in production taxes due to higher realized sales prices.

DRILLING PARTNERSHIP MANAGEMENT

We are a sponsor and manager of Drilling Partnerships in which we co-invest, to finance a portion of our drilling activities, and conduct certain energy activities through to support a portion of our natural gas, crude oil and natural gas liquids production activities and generate 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. 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.

As previously disclosed in the “Ability to Continue as a Going Concern” section, since the Plan Effective Date, our ability to raise capital through our Drilling Partnerships has been challenged. The decline in the fee-income generated from our Drilling Partnerships business has negatively impacted our ability to remain in compliance with the covenants under our credit facilities. See the “Ability to Continue as a Going Concern” section for further discussion regarding our liquidity and capital resources.

(in thousands)	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016
Drilling partnership management revenues	$ 7,610	$ 748	$ 15,390	$ 5,668
Drilling partnership management expenses	$ 5,310	$ (837)	$ 9,778	$ 1,306

Drilling partnership management revenues. Our Drilling partnership management revenues were higher in the current quarter and in the six months ended June 30, 2017 due to an increase of $7.1 million and $9.9 million, respectively, 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 higher in the current quarter and in the six months ended June 30, 2017 due to an increase of $6.2 million and $8.6 million, respectively, 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.

OTHER REVENUES AND EXPENSES

(in thousands)	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016
Other Revenues				
Gain (loss) on mark-to-market derivatives	$ 14,788	$ (67,162)	$ 40,993	$ (25,601)
Other Expenses				
General and administrative	$ 10,929	$ 20,934	$ 22,819	$ 36,808
Depreciation, depletion and amortization	12,806	25,311	26,468	52,687
Loss on divestiture	38,192	—	38,192	—
Interest expense	13,615	30,545	26,548	56,972
Gain on extinguishment of debt	—	—	—	26,498
Other income (loss)	(181)	(543)	(41)	(533)
Income tax provision (benefit)	(9,653)	—	(11,301)	—

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 three and six months ended June 30, 2017 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 Predecessor period three and six months ended June 30, 2016 were due to increases in commodity future prices relative to our Predecessor's derivative positions as of the respective prior period end.

General and Administrative. Our general and administrative expenses were lower in the three months ended June 30, 2017 due to a $6.6 million decrease in non-recurring transaction costs primarily due to our restructuring, a $1.7 million decrease in syndication expenses related to lower investment partnership program fundraising activities and employee reductions in 2017, a $1.0 million decrease in salaries and benefits expenses related to employee reductions in 2016 and a $1.5 million reduction in other corporate activities due to cost control measures implemented, partially offset by a $0.8 million increase in non-cash stock compensation.

Our general and administrative expenses were lower in the six months ended June 30, 2017 due to a $5.5 million decrease in non-recurring transaction costs primarily due to our restructuring, a $4.0 million decrease in salaries and benefits expenses related to employee reductions in 2016, a $3.2 million decrease in syndication expenses related to lower investment partnership program fundraising activities and employee reductions in 2017, and a $2.5 million reduction in other corporate activities due to cost control measures implemented, partially offset by a $1.3 million increase in non-cash stock compensation.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization expenses were lower in the current quarter due to a $9.8 million decrease in depletion expense and a $2.7 million decrease as a result of the application of fresh-start accounting to our proved gas and oil properties on September 1, 2016.

Our depreciation, depletion and amortization expenses were lower in the six months ended June 30, 2017 due to a $20.9 million decrease in depletion expense and a $5.3 million decrease as a result of the application of fresh-start accounting to our proved gas and oil properties on September 1, 2016.

Interest Expense. Interest expense during the Successor three months ended June 30, 2017 primarily consisted of $8.6 million related to our Second Lien Credit Facility, $4.6 million related to our First Lien Credit Facility, and $0.6 million related to amortization of deferred financing costs, partially offset by $0.2 million in capitalized interest. Interest expense during the Predecessor three months ended June 30, 2016 consisted of $14.1 million related to our Predecessor's senior notes, $7.5 million related to amortization of deferred financing costs and debt discounts, $6.3 million related to our Predecessor's second lien term loan, and $5.0 million related to our Predecessor's first lien credit facility, partially offset by $2.4 million in capitalized interest.

Interest expense during the Successor six months ended June 30, 2017 primarily consisted of $16.5 million related to our Second Lien Credit Facility, $9.1 million related to our First Lien Credit Facility, and $1.1 million related to amortization of deferred financing costs, partially offset by $0.2 million in capitalized interest. Interest expense during the Predecessor six months ended June 30, 2016 consisted of $28.5 million related to our Predecessor's senior notes, $12.6 million related to our Predecessor's second lien term loan, $11.3 related to amortization of deferred financing costs and debt discounts, and $9.4 million related to our Predecessor's first lien credit facility, partially offset by $4.8 million in capitalized interest.

Gain on Early Extinguishment of Debt. The gain on early extinguishment of debt for the Predecessor six months ended June 30, 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.

Income Tax Provision (Benefit). For the Successor period six months ended June 30, 2017, we recorded a full valuation allowance against our net deferred tax asset balance, which reduced our effective tax rate to 1.14%. 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 tax rate fluctuates as a result of the impact of state income taxes and permanent differences between our accounting for certain revenue or expense items and their corresponding treatment for income tax purposes. Our effective tax rate for the six months ended June 30, 2017 was 1.14%, which represents 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.

LIQUIDITY AND CAPITAL RESOURCES

See the “Liquidity and Ability to Continue as a Going Concern” section for discussion regarding these matters.

Cash Flows

	Successor	Predecessor
	Six Months Ended June 30,	
	2017	2016
(in thousands)		
Net cash provided by (used in) operating activities	$24,255	$(17,309)
Net cash provided by (used in) investing activities	33,994	(18,820)
Net cash provided by (used in) financing activities	(66,448)	59,034

Cash Flows From Operating Activities:

The increase in cash flows provided by operating activities was primarily due to:

- an increase of $45.1 million net cash provided by continuing operating activities and an increase of $4.9 million net cash provided by discontinued operating activities for cash receipts and disbursements attributable to our normal monthly operating cycle for gas and oil production and Drilling Partnership management revenues, and collections net of payments for royalties, lease operating expenses, gathering, processing and transportation expenses, severance taxes, Drilling Partnership management expenses, and general and administrative expenses;
- a decrease of $39.8 million of cash paid for interest due to a decrease of $28.5 million and $11.3 million in cash paid for interest related to our Predecessor's senior notes and second lien term loan, respectively, as a result of the Plan; and
- a decrease of $36.7 million of investor capital raised transferred by our Predecessor to the Atlas Eagle Ford 2015 L.P. private drilling partnership for activities directly related to their program; and
- a decrease of $5.2 million of funds transferred to certain Drilling Partnerships; partially offset by
- a decrease of $90.1 million of cash settlement receipts on commodity derivative contracts.

Cash Flows From Investing Activities:

The increase in cash flows provided by investing activities was due to a $66.6 million increase from the completion of the majority of the sale of our Appalachian Assets, partially offset by a $13.8 million increase in capital expenditures related to the timing and costs our drilling activities.

Cash Flows From Financing Activities:

The change in cash flows from financing activities was primarily due to:

- a decrease of $77.5 million in net borrowings under our Predecessor's revolving credit facility;
- a decrease of $12.6 million in distributions paid to our Predecessor's unitholders; and
- a decrease $5.5 million related to our Predecessor's senior note repurchases; partially offset by
- a $65.6 million increase in repayments under our First Lien Credit Facility.

Capital Requirements

At June 30, 2017, the capital requirements of our natural gas and oil production primarily consist of expenditures to maintain or increase production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisitions in the future, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of June 30, 2017, we are committed to expend approximately $2.8 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our Drilling Partnerships and borrowings under our revolving credit facility

OFF BALANCE SHEET ARRANGEMENTS

As of June 30, 2017, our off-balance sheet arrangements were limited to our letters of credit outstanding of $2.8 million and commitments to spend $2.8 million related to our drilling and completion and capital expenditures, excluding acquisitions.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

There have been no material changes to our contractual obligations and commercial commitments from those disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016, except for our well drilling and completion commitments is $2.3 million as of June 30, 2017 as compared to $19.4 million as of December 31, 2016.

CREDIT FACILITIES

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:

- 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 June 30, 2017, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 4.8%.
- 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 (the “First Lien Credit Facility Amendment”) to the First Lien Credit Facility with Wells Fargo, as administrative agent, and the lenders party thereto. Pursuant to the First Lien Credit Facility 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 are 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 First Lien Credit Facility Amendment confirms the conforming and non-conforming tranches of the borrowing base at $410 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 $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 will be required to be reduced to $10 million by November 1, 2017. In addition, we will be 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.

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:

- 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 will use 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 such notice began the 180-day 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. The lenders have not accelerated the payment of amounts outstanding under the Second Lien Credit Facility.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

For a more complete discussion of the accounting policies and estimates that we have identified as critical in the preparation of our condensed consolidated financial statements, please refer to our Management’s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

Recently Issued Accounting Standards

See Note 2 to our condensed consolidated financial statements for additional information related to recently issued accounting standards.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in interest rates and commodity prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of the market risk-sensitive instruments were entered into for purposes other than trading.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and interest rate cap and swap agreements. The following analysis presents the effect on our results of operations as if the hypothetical changes in market risk factors occurred on June 30, 2017. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

Interest Rate Risk. At June 30, 2017, $370.2 million was outstanding under our First Lien Credit Facility and $274.9 million was outstanding under our Second Lien Credit Facility. Holding all other variables constant, a hypothetical 1% change in variable interest rates would change our condensed consolidated interest expense for the twelve-month period ending June 30, 2018 by approximately $6.5 million.

Commodity Price Risk. Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our condensed consolidated operating income for the twelve-month period ending June 30, 2018 of approximately $0.1 million.

At June 30, 2017, we had the following commodity derivatives:

Type	Production Period Ending December 31,	Volumes[(1)]	Average Fixed Price[(1)]
Natural Gas – Fixed Price Swaps	2017[(2)]	25,839,800	$ 3.140
	2018	43,947,300	$ 2.959
Crude Oil – Fixed Price Swaps	2017[(2)]	392,900	$ 47.441
	2018	588,200	$ 50.284

(1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.
(2) The production volumes for 2017 include the remaining six months of 2017 beginning July 1, 2017.

ITEM 4: CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2017, our disclosure controls and procedures were effective at the reasonable assurance level.

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

PART II

ITEM 6: EXHIBITS

Exhibit Number	Description of Exhibit
2.1	Purchase and Sale Agreement by and among certain subsidiaries of Titan Energy, LLC and Diversified Energy LLC, dated May 4, 2017 (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed July 7, 2017)
2.2	First Amendment to Purchase and Sale Agreement by and among certain subsidiaries of Titan Energy, LLC and Diversified Energy LLC, dated June 30, 2017 (incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K filed July 7, 2017)
3.1(a)	Certification of Conversion of Titan Energy, LLC (incorporated by reference to Exhibit 3.1(a) to our Registration Statement on Form S-1 (File No. 333-214850) filed on November 30, 2016)
3.1(b)	Certificate of Formation of Titan Energy, LLC (incorporated by reference to Exhibit 3.1(b) to our Registration Statement on Form S-1 (File No. 333-214850) filed on November 30, 2016)
3.2	Amended and Restated Limited Liability Company Agreement of Titan Energy, LLC, dated as of September 1, 2016 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed September 7, 2016)
10.1	Second Amendment to Third Amended and Restated Credit Agreement, dated as of April 10, 2017, among Titan Energy Operating, LLC, as borrower, Titan Energy, LLC, as parent, the subsidiary guarantors party thereto, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1(c) to our Post-Effective Amendment No. 1 to Registration Statement on Form S-1 filed May 1, 2017)
10.2	Third Amendment to Third Amended and Restated Credit Agreement, dated as of April 19, 2017, among Titan Energy Operating, LLC, as borrower, Titan Energy, LLC, as parent, the subsidiary guarantors party thereto, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed April 21, 2017)
10.3	Second Amendment to Amended and Restated Second Lien Credit Agreement, dated as of April 10, 2017, among Titan Energy Operating, LLC, as borrower, Titan Energy, LLC, as parent, the subsidiary guarantors party thereto, and the lenders party thereto (incorporated by reference to Exhibit 10.2(c) to our Post-Effective Amendment No. 1 to Registration Statement on Form S-1 filed May 1, 2017)
10.4*	Retention Agreement between Titan Energy, LLC and Jeffrey M. Slotterback, effective May 15, 2017
10.5*	Retention Agreement between Titan Energy, LLC and Mark D. Schumacher, effective May 23, 2017
31.1*	Rule 13(a)-14(a)/15(d)-14(a) Certification

31.2*	Rule 13(a)-14(a)/15(d)-14(a) Certification
32.1*	Section 1350 Certification
32.2*	Section 1350 Certification
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

* Provided herewith.
** Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is “unaudited” or “unreviewed.”

SIGNATURES

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

TITAN ENERGY, LLC

Date:	August 21, 2017	By:	/s/ Daniel C. Herz Daniel C. Herz Chief Executive Officer and Director
Date:	August 21, 2017	By:	/s/ Jeffrey M. Slotterback Jeffrey M. Slotterback Chief Financial Officer
Date:	August 21, 2017	By:	/s/ Matthew J. Finkbeiner Matthew J. Finkbeiner Chief Accounting Officer