NETGEAR, INC
Form SC 13G/A
March 10, 2014

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

SCHEDULE 13G

Under the Securities Exchange Act of 1934
(Amendment No. 2)*

NETGEAR INC

(Name of Issuer)

Common

(Title of Class of Securities)

64111Q104

(CUSIP Number)

February 28, 2014

(Date of Event Which Requires Filing of this Statement)

Check the appropriate box to designate the rule pursuant to which this Schedule is filed:

x Rule 13d-1(b)

o Rule 13d-1(c)

o Rule 13d-1(d)

* The remainder of this cover page shall be filled out for a reporting person's initial filing on this form with respect to the subject class of securities, and for any subsequent amendment containing information which would alter the disclosures provided in a prior cover page.

The information required in the remainder of this cover page shall not be deemed to be "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934 ("Act") or otherwise subject to the liabilities of that section of the Act but shall be subject to all other provisions of the Act (however, see the Notes).

CUSIP No. 64111Q104

1	NAMES OF REPORTING PERSONS I.R.S. IDENTIFICATION NOS. OF ABOVE PERSONS (ENTITIES ONLY) Neuberger Berman Group LLC		
2	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP (SEE INSTRUCTIONS) (a) o (b) x		
3	SEC USE ONLY		
4	CITIZENSHIP OR PLACE OF ORGANIZATION Delaware		
NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH:	**5**	SOLE VOTING POWER 0	
	6	SHARED VOTING POWER 3801031	
	7	SOLE DISPOSITIVE POWER 0	
	8	SHARED DISPOSITIVE POWER 3809531	
9	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 3809531		

10	CHECK IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES (SEE INSTRUCTIONS) x
11	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 10.449%
12	TYPE OF REPORTING PERSON (SEE INSTRUCTIONS) HC

FOOTNOTES

CUSIP No. 64111Q104

1	NAMES OF REPORTING PERSONS I.R.S. IDENTIFICATION NOS. OF ABOVE PERSONS (ENTITIES ONLY) Neuberger Berman LLC		
2	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP (SEE INSTRUCTIONS) (a) o (b) x		
3	SEC USE ONLY		
4	CITIZENSHIP OR PLACE OF ORGANIZATION Delaware		
NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH:	**5**	SOLE VOTING POWER 0	
	6	SHARED VOTING POWER 3801031	
	7	SOLE DISPOSITIVE POWER 0	
	8	SHARED DISPOSITIVE POWER 3809531	
9	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 3809531		

10	CHECK IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES (SEE INSTRUCTIONS) x
11	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 10.449%
12	TYPE OF REPORTING PERSON (SEE INSTRUCTIONS) BD , IA FOOTNOTES

CUSIP No. 64111Q104

1	NAMES OF REPORTING PERSONS I.R.S. IDENTIFICATION NOS. OF ABOVE PERSONS (ENTITIES ONLY) Neuberger Berman Management LLC		
2	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP (SEE INSTRUCTIONS) (a) o (b) x		
3	SEC USE ONLY		
4	CITIZENSHIP OR PLACE OF ORGANIZATION Delaware		
NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH:	**5**	SOLE VOTING POWER 0	
	6	SHARED VOTING POWER 3404900	
	7	SOLE DISPOSITIVE POWER 0	
	8	SHARED DISPOSITIVE POWER 3404900	
9	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 3404900		

10	CHECK IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES (SEE INSTRUCTIONS) o
11	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 9.339%
12	TYPE OF REPORTING PERSON (SEE INSTRUCTIONS) BD

FOOTNOTES

CUSIP No. 64111Q104

1	NAMES OF REPORTING PERSONS I.R.S. IDENTIFICATION NOS. OF ABOVE PERSONS (ENTITIES ONLY) Neuberger Equity Funds		
2	CHECK THE APPROPRIATE BOX IF A MEMBER OF A GROUP (SEE INSTRUCTIONS) (a) o (b) x		
3	SEC USE ONLY		
4	CITIZENSHIP OR PLACE OF ORGANIZATION Delaware		
NUMBER OF SHARES BENEFICIALLY OWNED BY EACH REPORTING PERSON WITH:	**5**	SOLE VOTING POWER 0	
	6	SHARED VOTING POWER 3040400	
	7	SOLE DISPOSITIVE POWER 0	
	8	SHARED DISPOSITIVE POWER 3040400	
9	AGGREGATE AMOUNT BENEFICIALLY OWNED BY EACH REPORTING PERSON 3040400		

10	CHECK IF THE AGGREGATE AMOUNT IN ROW (9) EXCLUDES CERTAIN SHARES (SEE INSTRUCTIONS) o
11	PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9) 8.339%
12	TYPE OF REPORTING PERSON (SEE INSTRUCTIONS) IV
	FOOTNOTES

Item 1.

(a) Name of Issuer
NETGEAR, Inc.

(b) Address of Issuer's Principal Executive Offices
350 EAST PLUMERIA DRIVE
SAN JOSE, CA 95134

Item 2.

(a) Name of Person Filing
Neuberger Berman Group LLC
Neuberger Berman LLC
Neuberger Berman Management LLC
Neuberger Berman Equity Funds

(b) Address of Principal Business Office or, if none, Residence
605 Third Avenue
New York, NY 10158

(c) Citizenship
Delaware

(d) Title of Class of Securities
Common

(e) CUSIP Number
64111Q104

Item 3. If this statement is filed pursuant to §§240.13d-1(b) or 240.13d-2(b) or (c), check whether the person filing is a:

(a) o Broker or dealer registered under section 15 of the Act (15 U.S.C. 78o).

(b) o Bank as defined in section 3(a)(6) of the Act (15 U.S.C. 78c).

(c) o Insurance company as defined in section 3(a)(19) of the Act (15 U.S.C. 78c).

(d) o Investment company registered under section 8 of the Investment Company Act of 1940 (15 U.S.C 80a-8).

(e) o An investment adviser in accordance with §240.13d-1(b)(1)(ii)(E);

(f) o An employee benefit plan or endowment fund in accordance with §240.13d-1(b)(1)(ii)(F);

(g) o A parent holding company or control person in accordance with § 240.13d-1(b)(1)(ii)(G);

(h) o A savings associations as defined in Section 3(b) of the Federal Deposit Insurance Act (12 U.S.C. 1813);

(i) o A church plan that is excluded from the definition of an investment company under section 3(c)(14) of the Investment Company Act of 1940 (15 U.S.C. 80a-3);

(j) o A non-U.S. institution in accordance with § 240.13d-1(b)(1)(ii)(J).

(k) x A group, in accordance with § 240.13d-1(b)(1)(ii)(K). If filing as a non-U.S. institution in accordance with § 240.13d-1(b)(1)(ii)(J), please specify the type of institution:

Item 4. Ownership.

Provide the following information regarding the aggregate number and percentage of the class of securities of the issuer identified in Item 1.

(a) Amount beneficially owned: 3,809,531

(b) Percent of class: 10.449

(c) Number of shares as to which the person has:

(i) Sole power to vote or to direct the vote: 0

(ii) Shared power to vote or to direct the vote: 3,801,031

(iii) Sole power to dispose or to direct the disposition of: 0

(iv) Shared power to dispose or to direct the disposition of: 3,809,531

Item 5. Ownership of Five Percent or Less of a Class

If this statement is being filed to report the fact that as of the date hereof the reporting person has ceased to be the beneficial owner of more than five percent of the class of securities, check the following o .

Item 6. Ownership of More than Five Percent on Behalf of Another Person.

Neuberger Berman Group LLC and its affiliates may be deemed to be beneficial owners of securities for purposes of Exchange Act Rule 13d-3 because they or certain affiliated persons have shared power to retain, dispose of or vote the securities of unrelated clients. Neuberger Berman Group LLC or its affiliated persons do not, however, have any economic interest in the securities of those clients. The clients have the sole right to receive and the power to direct the receipt of dividends from or proceeds from the sale of such securities. No one client has an interest of more than 5% of the issuer.

With regard to the shares set forth under item 4(c)(ii), Neuberger Berman Group LLC may be deemed to be the beneficial owner for purposes of Rule 13d-3 because certain affiliated persons have shared power to retain, dispose of and vote the securities. In addition to the holdings of individual advisory clients, each of Neuberger Berman LLC and Neuberger Berman Management LLC serve as a sub-adviser and investment manager, respectively, of Neuberger Berman Group LLC's various registered mutual funds which hold such shares. The holdings belonging to clients of Neuberger Berman Trust Co N.A., Neuberger Berman Trust Co of Delaware N.A., NB Alternatives Advisers LLC and Neuberger Berman Fixed Income LLC, affiliates of Neuberger Berman LLC, are also aggregated to comprise the holdings referenced herein.

In addition to the shares set forth under Item 4(c)(ii) for which Neuberger entities also have shared power to dispose of the shares, item 4(c)(iv) also includes shares from individual client accounts over which Neuberger Berman LLC has shared power to dispose but does not have voting power over these shares. The holdings of Neuberger Berman Trust Co N.A., Neuberger Berman Trust Co of Delaware N.A., NB Alternatives Advisers LLC and Neuberger Berman Fixed Income LLC, affiliates of Neuberger Berman LLC, are also aggregated to comprise the holdings referenced herein.

Item 7. Identification and Classification of the Subsidiary Which Acquired the Security Being Reported on By the Parent Holding Company

Item 8. Identification and Classification of Members of the Group

Item 9. Notice of Dissolution of Group

Item 10. Certification

By signing below I certify that, to the best of my knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect.

SIGNATURE

After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

Neuberger Berman Group LLC

Date: March 10, 2014

By: /s/ Brad Cetron
Name: Brad Cetron
Title: Deputy General Counsel

Neuberger Berman LLC

Date: March 10, 2014

By: /s/ Brad Cetron
Name: Brad Cetron
Title: Deputy General Counsel

Neuberger Berman Management LLC

Date: March 10, 2014

By: /s/ Robert Conti
Name: Robert Conti
Title: President

Neuberger Berman Equity Funds

Date: March 10, 2014

By: /s/ Robert Conti
Name: Robert Conti

Title: President and Chief
Executive Officer

Footnotes: Item 4(a):

Neuberger Berman LLC, Neuberger Berman Management LLC, Neuberger Berman Trust Co N.A., Neuberger Berman Trust Co of Delaware N.A., NB Alternatives Advisers LLC and Neuberger Berman Fixed Income LLC and certain affiliated persons may be deemed to beneficially own the securities covered by this report in their various fiduciary capacities by virtue of the provisions of Exchange Act Rule 13d-3. Neuberger Berman Group LLC, through its subsidiary Neuberger Berman Holdings LLC, controls Neuberger Berman LLC, Neuberger Berman Management LLC, Neuberger Berman Trust Co N.A., Neuberger Berman Trust Co of Delaware N.A., NB Alternatives Advisers LLC and Neuberger Berman Fixed Income LLC and certain affiliated persons.

This report is not an admission that any of these entities are the beneficial owner of the securities covered by this report and each of Neuberger Berman Group LLC, Neuberger Berman Holdings LLC, Neuberger Berman LLC, Neuberger Berman Management LLC, Neuberger Berman Trust Co N.A., Neuberger Berman Trust Co of Delaware N.A., NB Alternatives Advisers LLC and Neuberger Berman Fixed Income LLC and certain affiliated persons disclaim beneficial ownership of the securities covered by this statement pursuant to Exchange Act Rule 13d-4.

Attention: Intentional misstatements or omissions of fact constitute Federal criminal violations (See 18 U.S.C. 1001)

:none;font-variant: normal;font-family:'Times New Roman';font-size:10pt;">access to sufficient amounts of carbon dioxide for tertiary recovery operations;

- uncertainties with respect to the success of drilling wells at identified drilling locations;
- acquisitions may potentially prove to be worth less than we paid, or provide less than anticipated proved reserves;
- ability to identify all risks associated with the acquisition of oil and natural gas properties, or existing wells, and the sufficiency of indemnifications we receive from sellers to protect us from such risks;
- expirations of undeveloped leasehold acreage;
- uncertainty regarding leasing operating expenses, general and administrative expenses and funding and development costs;
- exposure to financial and other liabilities of the managing general partners of the investment partnerships;
- the ability to comply with, and the potential costs of compliance with, new and existing federal, state, local and other laws and regulations applicable to our business and operations;
- restrictions on hydraulic fracturing;
- exposure to new and existing litigation;
- development of alternative energy resources; and
- the effects of a cyber event or terrorist attack.

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 predecessor’s Annual Report on Form 10-K for the fiscal year ended December 31, 2015 and in our predecessor’s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2016 and June 30, 2016. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

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

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

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

TITAN ENERGY. LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	Successor September 30, 2016	Predecessor December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 19,309	$ 1,353
Accounts receivable	29,177	63,367
Advances to affiliates	5,637	—
Current portion of derivative asset	—	159,460
Subscriptions receivable	—	19,877
Prepaid expenses and other	18,513	22,935
Total current assets	72,636	266,992
Property, plant and equipment, net	760,850	1,191,611
Goodwill and intangible assets, net	—	14,095
Long-term derivative asset	—	198,262
Other assets, net	11,145	28,989
Total assets	$ 844,631	$ 1,699,949
LIABILITIES AND MEMBERS' EQUITY / PARTNERS' CAPITAL (DEFICIT)		
Current liabilities:		
Accounts payable	$ 26,527	$ 49,249
Advances from affiliates	—	9,924
Liabilities associated with drilling contracts	—	21,483
Current portion of derivative liability	5,299	—
Derivative payable to Drilling Partnerships	458	2,574
Accrued well drilling and completion costs	15,491	26,914
Accrued interest	1,838	25,436
Distribution payable	—	4,334
Accrued liabilities	17,765	22,086
Current portion of long-term debt	30,000	—
Total current liabilities	97,378	162,000
Long-term debt, less current portion, net	658,222	1,503,427

Long-term derivative liability	3,659	—
Asset retirement obligations	59,190	113,740
Other long-term liabilities	7,629	5,410
Commitments and contingencies (Note 9)		
Members' Equity/Partners' Capital (Deficit):		
General partner's interest	—	(31,156)
Preferred limited partners' interests	—	188,739
Class C common limited partner warrants	—	1,176
Common limited partners' interests	—	(262,762)
Accumulated other comprehensive income	—	19,375
Series A Preferred members' interest	370	—
Common shareholders' interest	18,183	—
Total members' equity/partners' deficit	18,553	(84,628)
Total liabilities and members' equity/partners' deficit	$ 844,631	$ 1,699,949

See accompanying notes to condensed consolidated financial statements.

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TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share and unit data)

(Unaudited)

	Successor Period from September 1, 2016 through September 30, 2016	Predecessor Period from July 1, 2016 through August 31, 2016	Three Months Ended September 30, 2015	Period from January 1, 2016 through August 31, 2016	Nine Months Ended September 30, 2015
Revenues:					
Gas and oil production	$18,458	$39,205	$90,734	$139,094	$292,243
Well construction and completion	1,304	18,383	23,054	19,157	63,665
Gathering and processing	418	834	1,685	3,929	6,046
Administration and oversight	147	313	5,495	1,263	7,301
Well services	1,246	2,604	5,842	11,226	18,568
Gain (loss) on mark-to-market derivatives	(1,330)	3,228	131,065	(23,916)	209,706
Other, net	192	119	20	317	80
Total revenues	20,435	64,686	257,895	151,070	597,609
Costs and expenses:					
Gas and oil production	10,522	19,872	41,591	86,566	130,224
Well construction and completion	1,134	15,985	20,046	16,658	55,361
Gathering and processing	690	1,423	2,473	5,893	7,406
Well services	515	1,025	2,398	4,677	6,735
General and administrative	4,931	17,166	13,978	58,004	44,400
Depreciation, depletion and amortization	6,021	23,278	40,463	82,331	125,948
Asset impairment	—	—	672,246	—	672,246
Total costs and expenses	23,813	78,749	793,195	254,129	1,042,320
Operating loss	(3,378)	(14,063)	(535,300)	(103,059)	(444,711)
Interest expense	(3,810)	(14,928)	(25,192)	(74,587)	(75,105)
Gain (loss) on asset sales and disposal	10	14	(362)	(479)	(276)
Gain on early extinguishment of debt	—	—	—	26,498	—
Reorganization items, net	(353)	(16,614)	—	(16,614)	—
Other loss	—	(3,033)	—	(9,189)	—
Loss before income taxes	(7,531)	(48,624)	(560,854)	(177,430)	(520,092)

Income tax provision (benefit) - See Note 10	—	—	—	—	—
Net loss	(7,531)	(48,624)	(560,854)	(177,430)	(520,092)
Preferred member / limited partner dividends	—	—	(4,293)	(4,013)	(12,180)
Net loss attributable to common shareholders and preferred members	$(7,531)	$—	$—	$—	$—
Net loss attributable to common limited partners and the general partner	$—	$(48,624)	$(565,147)	$(181,443)	$(532,272)
Allocation of net loss attributable to:					
Preferred member	$(151)	$—	$—	$—	$—
Net loss attributable to common shareholders	$(7,380)	$—	$—	$—	$—
Common limited partners' interest	—	(47,651)	(553,844)	(177,814)	(524,113)
General partner's interest	—	(973)	(11,303)	(3,629)	(8,159)
Net loss attributable to common limited partners and the general partner	$—	$(48,624)	$(565,147)	$(181,443)	$(532,272)
Net loss attributable to common shareholders per share / common limited partners per unit (Note 2):					
Basic	$(1.36)	$(0.46)	$(5.73)	$(1.72)	$(5.76)
Diluted	$(1.36)	$(0.46)	$(5.73)	$(1.72)	$(5.76)
Weighted average shares / common limited partner units outstanding (Note 2):					
Basic	5,417	104,366	96,660	102,912	90,943
Diluted	5,417	104,366	96,660	102,912	90,943

See accompanying notes to condensed consolidated financial statements.

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TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in thousands)

(Unaudited)

	Successor Period from September 1, 2016 through September 30, 2016	Predecessor Period from July 1, 2016 through August 31, 2016	Three Months Ended September 30, 2015	Period from January 1, 2016 through August 31, 2016	Nine Months Ended September 30, 2015
Net loss	$(7,531)	$(48,624)	$(560,854)	$(177,430)	$(520,092)
Other comprehensive loss:					
Derivative instruments designated as cash flow hedges:					
Reclassification adjustment for unrealized gains used to offset impairment expense	—	—	(68,021)	—	(68,021)
Reclassification to net loss of mark-to-market gains	—	(1,688)	(23,927)	(10,758)	(77,048)
Reclassification adjustment for net reorganization gain included in net loss	—	(8,617)	—	(8,617)	—
Total other comprehensive loss	—	(10,305)	(91,948)	(19,375)	(145,069)
Comprehensive loss attributable to Preferred A member and common shareholders	$(7,531)	$—	$—	$—	$—
Comprehensive loss attributable to common and preferred limited partners and the general partner	$—	$(58,929)	$(652,802)	$(196,805)	$(665,161)

See accompanying notes to condensed consolidated financial statements.

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TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENT OF MEMBERS’ EQUITY / PARTNERS’ CAPITAL (DEFICIT)

(in thousands, except unit data)

(Unaudited)

al ers’ Interest A		Preferred Limited Partners’ Interest Class C		Class D		Class E		Common Limited Partners’ Interests		Class C Common Limited Partner Warrants	A O C In
	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Am
,445	$(31,156)	3,749,986	$85,402	4,090,328	$97,518	256,083	$5,819	102,160,866	$(262,762)	562,497	$1,$
3	—	—	—	—	—	—	—	245,175	204	—	—
	—	—	—	—	—	—	—	24,679	1,160	—	—
	39	—	637	—	2,205	—	172	—	1,277	—	—
	(156)	—	(2,550)	—	(4,410)	—	(344)	—	(5,118)	—	—
	—	—	—	—	—	—	—	—	(11)	—	—
	(3,629)	—	1,275	—	2,540	—	198	—	(177,814)	—	—
	—	(3,749,986)	(84,764)	—	—	—	—	3,749,986	85,940	(562,497)	$)(1,
	—	—	—	—	—	—	—	—	—	—	—

6,953)	34,902	—	—	(4,090,328)	(97,853)	(256,083)	(5,845)	(106,180,706)	357,124	—	—
	$—	—	$—	—	$—	—	$—	—	$—	—	—$

Successor	Series A Preferred Member's Equity Class A Shares	Amount	Common Shareholders' Equity Shares	Amount	Total Members' Equity
Balance at September 1, 2016	1	$ 521	5,416,667	$ 25,495	$ 26,016
Net issued and unissued shares under incentive plans	—	—	—	68	68
Net loss	—	(151)	—	(7,380)	(7,531)))
Balance at September 30, 2016	1	$ 370	5,416,667	$ 18,183	$ 18,553

See accompanying notes to condensed consolidated financial statements.

TITAN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Successor Period from September 1, 2016 through September 30, 2016	Predecessor Period from January 1, 2016 through August 31, 2016	Nine Months Ended September 30, 2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$(7,531)	$(177,430)	$(520,092)
Adjustments to reconcile net income loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	6,021	82,331	125,948
Asset impairment	—	—	672,246
Non-cash reorganization items	—	(10,312)	—
(Gain) loss on derivatives	1,308	7,346	(192,447)
(Gain) loss on asset sales and disposal	(10)	479	(190)
Gain on extinguishment of debt	—	(26,498)	—
Other (income) loss	—	9,189	—
Non-cash compensation expense	68	1,167	4,497
Non-cash interest expense	2,034	—	—
Provision for losses on Drilling Partnership receivables	—	10,906	—
Valuation allowance on deferred tax asset	—	1,596	—
Amortization of deferred financing costs and discount and premium on long-term debt	125	15,385	13,151
Changes in operating assets and liabilities:			
Monetization of derivatives	—	243,552	—
Accounts receivable, prepaid expenses and other	7,888	97,791	148,879
Accounts payable and accrued liabilities	(505)	(34,396)	(150,684)
Net cash provided by operating activities	9,398	221,106	101,308
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(5,367)	(24,894)	(102,290)
Net cash paid for acquisitions	—	—	(36,967)
Other	—	—	394

Net cash used in investing activities	(5,367)	(24,894)	(138,863)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under revolving credit facility	—	135,000	317,841
Repayments under revolving credit facility	—	(291,191)	(449,754)
Borrowings under second lien term loan facility	—	—	242,500
Senior note repurchases	—	(5,528)	—
Distributions paid to shareholders/unitholders	—	(12,578)	(119,703)
Net proceeds from issuance of common limited partner units	—	204	89,409
Net proceeds from issuance of preferred units	—	—	6,927
Arkoma transaction adjustment	—	—	(44,893)
Deferred financing costs, distribution equivalent rights and other	(150)	(8,044)	(17,601)
Net cash provided by (used in) financing activities	(150)	(182,137)	24,726
Net change in cash and cash equivalents	3,881	14,075	(12,829)
Cash and cash equivalents, beginning of period	15,428	1,353	15,247
Cash and cash equivalents, end of period	$19,309	$15,428	$2,418

See accompanying notes to condensed consolidated financial statements.

TITAN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1 – ORGANIZATION

We are an independent developer and producer of natural gas, crude oil and NGLs with operations in basins across the United States. 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, l and our consolidated subsidiaries (and its 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 ("Atlas Energy Group" or "ATLS"; OTC: ATLS), which is a publicly traded company.

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

At September 30, 2016, we had 5,416,667 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 (i) lenders holding 100% of ARP's senior secured revolving credit facility (the "First Lien Lenders"), (ii) lenders holding 100% of ARP's second lien term loan (the "Second Lien Lenders") and (iii) holders (the "Consenting Noteholders" and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that become party to the Restructuring Support Agreement, the "Restructuring Support Parties") of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the "7.75% Senior Notes") and the 9.25% Senior Notes due 2021 (the "9.25% Senior Notes" and, together with the 7.75% Senior Notes, the "Notes") of ARP's subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the "Issuers"). Under the Restructuring Support Agreement, the Restructuring Support Parties agreed, subject to certain terms and conditions, to support ARP's restructuring (the "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.”

ARP operated its businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords were unimpaired by the Plan and were satisfied in full in the ordinary course of business, and ARP’s existing trade contracts and terms were maintained. To assure ordinary course operations, ARP obtained interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to ARP, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

On September 1, 2016, (the “Plan Effective Date”), pursuant to the Plan, the following occurred:

- the 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 (Refer to Note 5 – Debt for further information regarding terms and provisions).
- the 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 (Refer to Note 5 – Debt for further information regarding terms and provisions). In

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addition, the Second Lien Lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.

- holders of the Notes, in exchange for 100% of the $668 million aggregate principal amount of 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 condensed consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2015 was derived from ARP's audited financial statements, have been prepared pursuant to the rules and regulations of the SEC and are presented in accordance with accounting principles generally accepted in the United States ("U.S. GAAP") for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. It is suggested that these interim condensed consolidated financial statements be read in conjunction with the financial statements and the notes thereto included in ARP's latest Annual Report on Form 10-K though, as described below, such prior financial statements may not be comparable to our interim financial statements due to the adoption of fresh-start accounting. In management's opinion, all adjustments necessary for a fair presentation of our and ARP's financial position, results of operations and cash flows for the periods disclosed have been made. Certain amounts in the prior year's financial statements have been reclassified to conform to the current year presentation due to the adoption of certain accounting standards (see Notes 2 and 5). The results of operations for the interim periods presented may not necessarily be indicative of the results of operations for the full year.

In connection with ARP's Chapter 11 filings, we were subject to the provisions of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 852 Reorganizations ("ASC 852"). All expenses, realized gains and losses and provisions for losses directly associated with the bankruptcy proceedings were classified as "reorganization items" in the condensed consolidated statements of operations.

Upon emergence from bankruptcy on the Plan Effective Date, we adopted fresh-start accounting in accordance with ASC 852, which resulted in Titan becoming a new entity for financial reporting purposes. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Plan Effective Date, which differed materially from the recorded values of ARP's assets and liabilities as reflected in ARP's historical consolidated balance sheets. The effects of the Plan and the application of fresh-start accounting were reflected in our consolidated financial statements as of September 1, 2016 and the related adjustments thereto were recorded in our condensed consolidated statements of operations as reorganization items for the predecessor period January 1 to August 31, 2016.

As a result, our condensed consolidated balance sheet and condensed consolidated statement of operations subsequent to the Plan Effective Date will not be comparable to ARP's condensed consolidated balance sheet and condensed consolidated statements of operations prior to the Plan Effective Date. Our 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 September 1, 2016 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 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.

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 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

Our primary sources of liquidity are cash generated from operations, capital raised through our Drilling Partnerships, and borrowings under our credit facilities. Our primary cash requirements are operating expenses, debt service including interest, and capital expenditures.

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. 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 have continued to decline and remain low in 2016. 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, challenges with our ability to raise capital through our Drilling Partnerships, either as a result of downturn in commodity prices or other difficulties affecting the fundraising channel, could negatively impact our ability to remain in compliance with the covenants under our credit facilities.

If we are unable to remain in compliance with the covenants under our credit facilities (as described in Note 5), absent relief from our lenders, as applicable, we may be forced to repay or refinance such indebtedness. Upon the occurrence of an 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. If an event of default occurs (including if our borrowing base is redetermined below our current outstanding borrowings and we are unable to repay the deficiency or deposit additional collateral to eliminate such deficiency), or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we will not have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there would be substantial doubt regarding our ability to continue as a going concern.

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, meeting our debt service obligations and/or achieving cost efficiency. For example, 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 also continue to implement various cost saving measures to reduce our capital, operating and general and administrative costs, including renegotiating contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs. We will continue to be opportunistic and aggressive in managing our cost structure and, in turn, our liquidity to meet our capital and operating needs. We cannot provide any assurances that any of these efforts will be successful or will result in cost reductions or cash flows or the timing of any such cost reductions or additional cash flows. It is also possible additional adjustments to our plan and outlook may occur based on market conditions and our needs at that time, which could include selling assets, seeking additional partners to develop our assets, and/or reducing our planned capital program. In addition, to the extent commodity prices remain low or decline further, or we experience disruptions in our longer-term access to or cost of capital, our ability to fund future capital expenditures or growth projects may be further impacted.

Arkoma Acquisition

On June 5, 2015, ARP acquired coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma from ATLS (the “Arkoma Acquisition”) for $31.5 million, net of purchase price adjustments, which was funded through the issuance of 6,500,000 of our Predecessor’s common limited partner units. We determined that the Arkoma Acquisition constituted a transaction between entities under common control and, accordingly, retroactively adjusted ARP’s prior period condensed consolidated financial statements assuming our Predecessor’s common limited partners participated in the net income (loss) of the Arkoma operations before the date of the transaction.

In April 2015, the FASB updated the accounting guidance for earnings per unit ("EPU") of master limited partnerships ("MLP") applying the two-class method. The updated accounting guidance specifies that for general partner transfers (or "drop downs") to an MLP accounted for as a transaction between entities under common control, the earnings (losses) of the transferred business before the date of the transaction should be allocated entirely to the general partner's interest, and previously reported EPU of the limited partners should not change. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the drop down transaction occurs are also required.

ARP adopted this accounting guidance upon its effective date of January 1, 2016, which resulted in the following retrospective restatement to allocate the net income (loss) of the Arkoma operations before the date of the transaction entirely to our Predecessor's general partner's interest:

Predecessor Condensed Consolidated Statement of Operations	Previously Filed	Adjustment	Restated
Nine Months Ended September 30, 2015:			
Common limited partners' interest	$(521,627)	$ (2,486)	$(524,113)
General partner's interest	$(10,645)	$ 2,486	$(8,159)
Net loss attributable to common limited partners per unit – basic	$(5.74)	$ (0.02)	$(5.76)
Net loss attributable to common limited partners per unit – diluted	$(5.74)	$ (0.02)	$(5.76)
Predecessor Condensed Consolidated Balance Sheet			
December 31, 2015:			
Common limited partners' interest	$(260,276)	$ (2,486)	$(262,762)
General partners' interest	$(33,642)	$ 2,486	$(31,156)

Prior to the Arkoma Acquisition, our Predecessor's common limited partners did not participate in the net income (loss) of the Arkoma operations. Subsequent to the Arkoma Acquisition, our Predecessor's common limited partners participated in the net income (loss) of the Arkoma operations, which was determined after the deduction of our Predecessor's general partner's and preferred unitholders' interests.

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, depreciation and amortization, fair value of derivative instruments, fair value of certain gas and oil properties and asset retirement obligations, and fair value of assets and liabilities in connection with the application of fresh-start accounting. 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.

Predecessor's Net Income Per Common Unit

Basic net income attributable to our Predecessor's common limited partners per unit was computed by dividing net income attributable to our Predecessor's common limited partners, which was determined after the deduction of our Predecessor's general partner's and preferred unitholders' interests, by the weighted average number of our Predecessor's common limited partner units outstanding during the period. Net income attributable to our Predecessor's common limited partners was determined by deducting net income attributable to participating securities, if applicable, income attributable to our Predecessor's preferred limited partners and net income attributable to our Predecessor's general partner's Class A units. Our Predecessor's general partner's interest in net income was calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 10), with a priority allocation of net income to our Predecessor's general partner's incentive distributions, if any, in accordance with our Predecessor's partnership agreement, and the remaining net income allocated with respect to our Predecessor's general partner's and limited partners' ownership interests.

Our Predecessor presented net income per unit under the two-class method for MLPs, which considers whether the incentive distributions of a MLP represent a participating security. The two-class method considers whether our Predecessor's partnership agreement contained any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights' share of currently designated available cash for distributions as defined under our Predecessor's partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management believed our Predecessor's partnership agreement contractually limited cash distributions to available cash; therefore, undistributed earnings were not allocated to the incentive distribution rights.

Unvested unit-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. Phantom unit awards, which consist of common units issuable under the terms of our long-term incentive plan, contain non-forfeitable rights to distribution equivalents. The participation rights would result in a non-contingent transfer of value each time we declare a distribution or distribution equivalent right during the award's vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. As such, the net income utilized in the calculation of net income per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

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

	Predecessor	
	Period from July 1 – August 31, 2016	Three Months Ended September 30, 2015
Net loss	$(48,624)	$(560,854)
Preferred limited partner dividends	—	(4,293)
Net income (loss) attributable to common limited partners and the general partner	(48,624)	(565,147)
Less: General partner's interest	(973)	(11,303)
Net loss attributable to common limited partners	(47,651)	(553,844)
Less: Net loss attributable to participating securities – phantom units	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Basic	(47,651)	(553,844)
Plus: Convertible preferred limited partner dividends[1]	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Diluted	$(47,651)	$(553,844)

	Predecessor	
	Period from January 1 – August 31, 2016	Nine Months Ended September 30, 2015
Net loss	$(177,430)	$(520,092)
Preferred limited partner dividends	(4,013)	(12,180)
Net loss attributable to common limited partners and the general partner	(181,443)	(532,272)
Less: General partner's interest	(3,629)	(8,159)
Net loss attributable to common limited partners	(177,814)	(524,113)

Less: Net loss attributable to participating securities – phantom units	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Basic	(177,814)	(524,113)
Plus: Convertible preferred limited partner dividends[1]	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Diluted	$(177,814)	$(524,113)

(1) For all predecessor 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.

Diluted net income attributable to our Predecessor's common limited partners per unit was calculated by dividing net income attributable to our Predecessor's common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, convertible preferred units and warrants, as calculated by the treasury stock or if converted methods, as applicable. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of our long-term incentive plan.

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 attributable to our Predecessor's common limited partners per unit with those used to compute diluted net income attributable to our Predecessor's common limited partners per unit (in thousands):

	Predecessor Period from July 1, 2016 through August 31, 2016	Three Months Ended September 30, 2015	Period from January 1, 2016 through August 31, 2016	Nine Months Ended September 30, 2015
Weighted average number of common limited partner units—basic	104,366	96,660	102,912	90,943
Add effect of dilutive incentive awards(1)	—	—	—	—
Add effect of dilutive convertible preferred limited partner units(2)	—	—	—	—
Weighted average number of common limited partner units—diluted	104,366	96,660	102,912	90,943

(1) For the period from July 1, 2016 through August 31, 2016, the period January 1, 2016 through August 31, 2016 and the three and nine months ended September 30, 2015, 247,000, 274,000, 346,000 and 501,000 phantom 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.

(2) For the three and nine months ended September 30, 2015, potential common limited partner units issuable upon (a) conversion of our Class C preferred units and (b) exercise of the common unit warrants issued with the 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 the Class D and Class E preferred units are 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 August 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs specific to line of credit arrangements. The updated accounting guidance allows the option of presenting deferred debt issuance costs related to line-of-credit arrangements as an asset, and subsequently amortizing over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. We adopted the updated accounting guidance effective January 1, 2016, and it did not have a material impact on our condensed consolidated financial statements.

In February 2015, the FASB updated the accounting guidance related to consolidation under the variable interest entity and voting interest entity models. The updated accounting guidance modifies the consolidation guidance for variable interest entities, limited partnerships and similar legal entities. We adopted this accounting guidance upon its effective date of January 1, 2016, and it did not have a material impact on our condensed consolidated financial statements.

In August 2014, the FASB updated the accounting guidance related to the evaluation of whether there is substantial doubt about an entity's ability to continue as a going concern. The updated accounting guidance requires an entity's management to evaluate whether there are conditions or events that raise substantial doubt about its ability to continue as a going concern within one year from the date the financial statements are issued and provide footnote disclosures, if necessary. We adopted this accounting guidance on January 1, 2016, and provided enhanced disclosures, as applicable, within 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. The updated accounting guidance provides companies with alternative methods of adoption. We are currently in the process of determining the impact that the updated accounting guidance will have on our condensed consolidated financial statements and our method of adoption.

NOTE 3 – 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 of the Plan was less than the post-petition liabilities and allowed claims, and (ii) the holders of existing voting shares of our Predecessor received less than 50% of the voting shares of the post-emergence Successor entity.

Reorganization Value: Reorganization value represents the fair value of the Successor's total assets and is intended to approximate the amount a willing buyer would pay for the assets immediately after restructuring. Under fresh-start accounting, we allocated the reorganization value to our individual assets based on their estimated fair values.

Our reorganization value was derived from an estimate of enterprise value. Enterprise value represents the estimated fair value of an entity's long term debt and shareholders' equity. The estimated enterprise value of the Successor of approximately $714.3 million represents management's best estimate of fair value on the Plan Effective Date and is within the range of value contemplated by the Bankruptcy Court in confirmation of the Plan after extensive negotiations among the Company and its creditors.

We estimated the enterprise value of the Successor utilizing the discounted cash flow method. To estimate fair value utilizing the discounted cash flow method, we established an estimate of future cash flows for both our gas and oil production business and our partnership management business based on the financial projections in our disclosure statement. The financial projections for our gas and oil production business were based on our forecast, which includes a number of assumptions regarding future anticipated performance of reserves including decline curves for existing proved developed producing wells, as well as new wells brought online, commodity pricing and average realized pricing, and reductions for operating costs and general and administrative expenses. The financial projections for our partnership management business were based on our forecast, which includes a number of assumptions regarding future anticipated performance including existing fee revenue streams and future annual partnership capital fund raises, based on historical averages. A terminal value was included for the partnership management business, and was calculated using a long-term growth rate of 1% on the projected cash flows of the final year of the forecast period.

The discount rates of 10% for our gas and oil production business and 12% for our partnership management business were estimated based on an after-tax weighted average cost of capital ("WACC") derived from a comparable set of publicly-held companies reflecting the rate of return that would be expected by a market participant within each respective business. The WACC also takes into consideration a company-specific risk premium, reflecting the risk associated with the overall uncertainty of the financial projections used to estimate future cash flows.

A reconciliation of the reorganization value was provided in the table below:

Enterprise value	$714,325
Plus: Cash and cash equivalents	15,428
Plus: Working capital surplus	63,222
Plus: Other liabilities	70,183
Reorganization value of Successor assets	$863,158

Consolidated Balance Sheet

The adjustments set forth in the following condensed consolidated balance sheet reflect the effect of the consummation of the transactions contemplated by the Plan (reflected in the column "Reorganization Adjustments") as well as fair value adjustments as a result of the adoption of fresh-start accounting (reflected in the column "Fresh Start

Adjustments”). The explanatory notes highlight methods used to determine fair values or other amounts of the assets and liabilities as well as significant assumptions or inputs.

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	Predecessor August 31, 2016	Reorganization Adjustments		Fresh Start Adjustments		Successor September 1, 2016
ASSETS						
Current assets:						
Cash and cash equivalents	$35,688	$ (20,260	)(a)	$—		$15,428
Accounts receivable	56,621	—		(56	)(a)	56,565
Advances to affiliates	5,592	—		—		5,592
Prepaid expenses and other	18,635	—		—		18,635
Total current assets	116,536	(20,260	)	(56	)	96,220
Property, plant and equipment, net	1,154,866	—		(396,661	)(b)	758,205
Goodwill	13,639	—		(13,639	)(c)	—
Other assets, net	15,773	(7,040	)(b)	—		8,733
Total assets	$1,300,814	$ (27,300	)	$(410,356	)	$863,158
LIABILITIES AND PARTNERS' CAPITAL (DEFICIT) / MEMBERS' EQUITY						
Current liabilities:						
Accounts payable	$49,324	$ —		$—		$49,324
Derivative payable to Drilling Partnerships	534	—		—		534
Current portion of derivative liability	3,087	—		—		3,087
Accrued well drilling and completion costs	12,322	—		—		12,322
Accrued interest	3,210	(3,210	)(c)	—		—
Accrued liabilities	18,311	—		(2,774	)(d)	15,537
Current portion of long-term debt	30,000	—		—		30,000
Total current liabilities	116,788	(3,210	)	(2,774	)	110,804
Long-term debt, less current portion, net	405,809	250,346	(d)	—		656,155
Long-term derivative liability	4,259	—		—		4,259
Asset retirement obligations	130,935	—		(72,067	)(e)	58,868
Other long-term liabilities	7,108	—		(52	)(f)	7,056
Liabilities subject to compromise	915,626	(915,626	)(e)	—		—
Commitments and contingencies (Note 9)						
Partners' Capital (Deficit) / Members' Equity:						
General partner's interest	$(34,902)	$ 34,902	(f)	—		—
Preferred limited partners' interests	103,698	(103,698	)(f)	—		—
Common limited partners' interests	(357,124)	357,124	(f)	—		—

Accumulated other comprehensive income	8,617	(8,617)(f)	—	—
Series A Preferred member's interest	—	7,230 (g)	(6,709)(g)	521
Common shareholders' interests	—	354,249 (g)	(328,754)(g)	25,495
Total partners' deficit / members' equity	(279,711)	641,190	(335,463)	26,016
Total liabilities and partners' deficit / members' equity	$1,300,814	$ (27,300)	$(410,356)	$863,158

Reorganization Adjustments:

(a) Reflects the use of cash on the Plan Effective Date from implementation of the Plan:

First Lien Credit Facility deferred financing costs	$ (2,525)
Second Lien Credit Facility deferred financing costs	(1,838)
Accrued interest on old first lien credit facility	(3,210)
Accrued interest on old second lien credit facility	(2,375)
Professional fees	(10,312)
Total uses	$ (20,260)

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(b) Reflects the adjustment made to record the elimination of $9.6 million of the old first lien credit facility deferred financing costs offset by the recognition of $2.5 million in additional deferred financing costs related to the new First Lien Credit Facility.

(c) Reflects the payment of $3.2 million of accrued interest related to the old first lien credit facility pursuant to the Plan.

(d) Reflects the incurrence of indebtedness under the Second Lien Credit Facility, which has an aggregate principal amount of $252.5 million pursuant to the Plan, and is net of deferred financing costs of $2.2 million.

(e) Liabilities subject to compromise were settled as follows in accordance with the Plan:

Liabilities subject to compromise (“LSTC”):	
7.75% and 9.25% Senior Notes, net of debt discount and deferred financing costs	$ 648,612
Old second lien credit facility, net of debt discount and deferred financing costs	234,451
Accrued interest related to the Senior Notes and old second lien credit facility	32,563
LSTC of Predecessor	915,626
Issuance of Second Lien Credit Facility	(252,500)
Payment of accrued interest related to the old second lien credit facility	(2,375)
Second Lien Credit Facility deferred financing costs reinstated	316
Gain on the settlement of LSTC	$661,067

(f) Reflects the cancellation of our Predecessor’s general partner’s interest, preferred limited partners’ interests, common limited partner interests and accumulated other comprehensive income pursuant to the Plan.

(g) Reflects the establishment of member’s equity following the consummation of the transactions pursuant to the Plan. Pursuant to our amended and restated limited liability company agreement, the holder of the Series A Preferred Share is entitled to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members’ equity), subject to dilution if certain catch-up contributions are not made with respect to future equity issuances.

Reflects the cumulative impact of reorganization adjustments as discussed above:	
Gain on liabilities subject to compromise	$ 661,067
Cancellation of Predecessor's capital interests	(279,711)
Net cash, deferring financing costs, and other adjustments	(19,877)
Total impact of reorganization adjustments	$361,479
Allocation of total impact of reorganization adjustments to establish members’ equity:	
Series A Preferred member's interest	$ 7,230
Common shareholders’ interests	$ 354,249

Fresh Start Accounting Adjustments:

(a) Reflects the adjustment of certain accounts receivable to their estimated fair value.

(b) Reflects the following adjustments made to record property, plant and equipment, net at its estimated fair value. The fair values of proved natural gas and oil properties and support equipment and other were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair value of unproved properties was the result of the excess reorganization value over the fair value of identified tangible and intangible assets and represents the value of our probable and possible drilling locations within our various acreage positions.

	Predecessor	Fresh Start Adjustments	Successor
Natural gas and oil properties:			
Proved properties	$3,620,371	$(2,946,257)	$ 674,114
Unproved properties	213,047	(142,783)	70,264
Support equipment and other	131,587	(117,760)	13,827
Total natural gas and oil properties	3,965,005	(3,206,800)	758,205
Accumulated depreciation, depletion and amortization	(2,810,139)	2,810,139	—

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Property, plant and equipment, net	$1,154,866	$	(396,661)	$	758,205

(c) Reflects the adjustment made to record the elimination of the Predecessor's goodwill.

(d) Reflects the adjustment of certain accrued liabilities to their estimated fair value.

(e) Reflects the adjustment made to record asset retirement obligations at fair value. The fair value of asset retirement obligations was measured using a discounted cash flow model based on management'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, and federal and state regulatory requirements. We used the discount rate consistent with the rate used for our gas and oil production business.

(f) Reflects the adjustment of certain other long-term liabilities to their estimated fair value

(g) Reflects the adjustment to members' equity following the fresh start accounting adjustments. Pursuant to our LLC Agreement, the holder of the Series A Preferred Share is entitled to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity), subject to dilution if certain catch-up contributions are not made with respect to future equity issuances.

Reflects the cumulative impact of fresh start adjustments as discussed above:	
Property, plant, and equipment, net fair value adjustment	$ (396,661)
Elimination of Predecessor's goodwill	(13,639)
Accounts receivable fair value adjustment	(56)
Other liabilities fair value adjustment	52
Accrued liabilities fair value adjustment	2,774
Asset retirement fair value adjustment	72,067
Total impact of fresh start adjustments	$ (335,463)
Allocation of total impact of fresh start adjustments to members' equity:	
Series A Preferred member's interest	$ (6,709)
Common shareholders' interest	$ (328,754)

Reorganization Items, net:

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

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

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	Successor September 30, 2016	Predecessor December 31, 2015
Natural gas and oil properties:		
Proved properties	678,208	3,585,839
Unproved properties	74,434	213,047
Support equipment and other	13,080	130,691
Total natural gas and oil properties	765,722	3,929,577
Less – accumulated depreciation, depletion and amortization	(4,872)	(2,737,966)
	$ 760,850	$ 1,191,611

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During the Successor period from September 1, 2016 through September 30, 2016, the Predecessor periods from January 1, 2016 through August 31, 2016 and the nine months ended September 30, 2015, we recognized $0.4 million, $18.7 million and $5.2 million, respectively, of non-cash property, plant and equipment additions, which was included 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 period September 1, 2016 through September 30, 2016, the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 and the three and nine months ended September 30, 2015 was 7.6%, 6.0%, 6.5%, 6.5%, and 6.4%, respectively. The aggregate amount of interest capitalized during the Successor period September 1, 2016 through September 30, 2016, the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 and the three and nine months ended September 30, 2015 was $0.7 million, $1.7 million, $6.5 million, $4.0 million, and $12.0 million, respectively.

During the Successor period September 1, 2016 through September 30, 2016, the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 and the three and nine months ended September 30, 2015, $0.5 million, $1.3 million, $4.6 million, $1.6 million and $4.7 million, respectively, of accretion expense was recorded related to our asset retirement obligations within depreciation, depletion and amortization in our condensed consolidated statements of operations. For the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor recorded additional asset retirement obligation liabilities of $12.9 million in our condensed consolidated balance sheets due to the liquidation of some of our Predecessor's Drilling Partnerships.

NOTE 5 – DEBT

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

	Successor September 30, 2016	Predecessor December 31, 2015
First Lien Credit Facility	$ 435,809	$ —
Second Lien Credit Facility	254,534	—
Old First Lien Credit Facility	—	592,000
Old Second Lien Term Loan	—	243,783
7.75 % Senior Notes – due 2021	—	374,619
9.25 % Senior Notes – due 2021	—	324,080
Deferred financing costs	(2,121)	(31,055)
Total debt, net	688,222	1,503,427
Less current maturities	(30,000)	—
Total long-term debt, net	$ 658,222	$ 1,503,427

In April 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs. The updated accounting guidance requires that debt issuance costs be presented as a direct deduction from the associated debt obligation. We adopted this accounting guidance upon its effective date of January 1, 2016. The retrospective effect of the reclassification resulted in the following changes to our Predecessor's balance sheet:

Predecessor's Condensed Consolidated Balance Sheet	Previously Filed	Adjustment	Restated
December 31, 2015:			
Other assets, net	$60,044	$ (31,055)	$28,989
Long-term debt, net	$1,534,482	$ (31,055)	$1,503,427

Cash Interest. Total cash payments for interest by us for the Successor period September 1, 2016 through September 30, 2016, the predecessor period from January 1, 2016 through August 31, 2016 and the three and nine months ended September 30, 2015, were $0.5 million, $53.7 million, $40.4 million and $87.7 million, respectively. There were no cash payments for interest for the predecessor period from July 1, 2016 through August 31, 2016.

First Lien Credit Facility

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On September 1, 2016, we entered into a $440 million third amended and restated first lien credit agreement with Wells Fargo Bank, National Association ("Wells Fargo"), as administrative agent, and the lenders party thereto (the "First Lien Credit Facility"). 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.
- The non-conforming tranche matures on May 1, 2017 and the conforming reserve-based tranche matures on August 23, 2019.
- Borrowing base will be redetermined semi-annually, with additional interim re-determinations permitted under certain circumstances. The first scheduled borrowing base redetermination shall occur on May 1, 2017; provided, that a super majority of the lenders may elect, in certain circumstances, to seek an interim redetermination of the borrowing base prior to May 1, 2017.
- Obligations are secured by mortgages on substantially all of our oil and gas properties and first priority security interests in substantially all of our assets and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.
- Borrowings bear interest at our election at either LIBOR plus an applicable margin between 3.00% and 4.00% per annum or the "alternate base rate" plus an applicable margin between 2.00% and 3.00% per annum, which fluctuates based on utilization. We are also required to pay a fee of 0.50% per annum on the unused portion of the borrowing base. At September 30, 2016, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 5.1%.
- 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.
- Requires us to maintain certain financial ratios (which will first be tested for the period ending December 31, 2016 and will use an annualized EBITDA measurement for periods prior to June 30, 2017):
  - Total Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 5.00 to 1.00;
  - Current assets to current liabilities (each as defined in the First Lien Credit Facility) of not less than 1.00 to 1.00;
  - First Lien Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 3.50 to 1.00; and
  - EBITDA to Interest Expense (each as defined in the First Lien Credit Facility) of not less than 2.50 to 1.00.

Second Lien Credit Facility

On September 1, 2016, we entered into an amended and restated second lien credit agreement with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto (the "Second Lien Credit Facility") 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 limits 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 first be tested for the period ending December 31, 2016 and will use an annualized EBITDA measurement for periods prior to June 30, 2017):
  - o EBITDA to Interest Expense (each as defined in the Second Lien Credit Facility) of not less than 2.50 to 1.00;
  - o 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.

Old First Lien Credit Facility

Our Predecessor was party to a Second Amended and Restated Credit Agreement, dated as of July 31, 2013 by and among our Predecessor, the lenders from time to time party thereto, and Wells Fargo, as administrative agent, as amended, supplemented or modified from time to time (the “Old First Lien Credit Facility”), which provided for a senior secured revolving credit facility with a maximum borrowing base of $1.5 billion and was scheduled to mature in July 2018.

Pursuant to the Restructuring Support Agreement, our Predecessor completed the sale of substantially all our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the Old First Lien Credit Facility. As of August 31, 2016 under our Predecessor, the weighted average interest rate on outstanding borrowings under the Old First Lien Credit Facility was 5.5%. Pursuant to the Plan, the Old First Lien Credit Facility was replaced by the First Lien Credit Facility (see Note 1).

Old Second Lien Term Loan

Our Predecessor was party to a Second Lien Credit Agreement, dated as of February 23, 2015 by and among our Predecessor, the lenders from time to time party thereto, and Wilmington Trust, National Association, as administrative agent, as amended, supplemented or modified from time to time (the “Old Second Lien Term Loan”), which provided for a second lien term loan in an original principal amount of $250.0 million.

As of August 31, 2016 under our Predecessor, the weighted average interest rate on outstanding borrowings under the Old Second Lien Term Loan was 10.0%. Pursuant to the Plan, the Old Second Lien Term Loan was replaced by the Second Lien Facility (see Note 1).

Senior Notes

In January and February 2016, our Predecessor executed transactions to repurchase $20.3 million of our 7.75% Senior Notes and $12.1 million of our 9.25% Senior Notes for $5.5 million, which included $0.6 million of interest. As a result of these transactions, our Predecessor recognized $26.5 million as gain on early extinguishment of debt, net of accelerated amortization of deferred financing costs of $0.9 million, in the condensed consolidated statement of operations for the Predecessor period from January 1, 2016 through August 31, 2016.

Pursuant to the Plan, Holders of the Notes, in exchange for 100% of the $668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of the common equity interests of us (see Note 1).

NOTE 6 – DERIVATIVE INSTRUMENTS

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

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

Pursuant to the Restructuring Support Agreement, our Predecessor completed the sale of substantially all of its commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the Old First Lien Credit Facility.

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

	Successor	Predecessor			
	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Period from January 1, 2016 through August 31, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
Portion of settlements associated with gains (losses) previously recognized within accumulated other comprehensive income, net of prior year offsets[(1)(2)]	$ —	$ 1,688	$ 10,758	$ 23,927	$ 77,048
Portion of settlements attributable to subsequent mark to market gains[(2)]	283	3,996	89,041	19,555	49,680
Total cash settlements on commodity derivative contracts[(2)]	$ 283	$ 5,684	$ 99,799	$ 43,482	$ 126,728
Gains (losses) recognized on cash settlement[(3)]	$ (22)	$ 10,574	$ (16,570)	$ 10,426	$ 17,259
Gains (losses) recognized on open derivative contracts[(3)]	(1,308)	(7,346)	(7,346)	120,639	192,447
Gains (losses) on mark-to-market derivatives	$ (1,330)	$ 3,228	$ (23,916)	$ 131,065	$ 209,706

(1) Recognized in gas and oil production revenue.
(2) Excludes the effects of the $235.3 million, net of $8.2 million in hedge monetization fees, paid directly to the First Lien Credit Facility lenders upon the sale of substantially all of our Predecessor's commodity hedge positions on July 25, 2016 and July 26, 2016.
(3) 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):

Successor Offsetting Derivatives as of September 30, 2016	Gross Amounts	Gross Amounts	Net Amount

	Recognized	Offset	Presented
Current portion of derivative assets	$ 2,905	$ (2,905)	$ —
Long-term portion of derivative assets	5,419	(5,419)	—
Total derivative assets	$ 8,324	$ (8,324)	$ —
Current portion of derivative liabilities	$ (8,204)	$ 2,905	$ (5,299)
Long-term portion of derivative liabilities	(9,078)	5,419	(3,659)
Total derivative liabilities	$ (17,282)	$ 8,324	$ (8,958)
Predecessor Offsetting Derivatives as of December 31, 2015			
Current portion of derivative assets	$ 159,460	$ —	$ 159,460
Long-term portion of derivative assets	198,262	—	198,262
Total derivative assets	$ 357,722	$ —	$ 357,722
Current portion of derivative liabilities	$ —	$ —	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ —	$ —	$ —

At September 30, 2016, we had the following commodity derivatives:

Type	Production Period Ending December 31,	Volumes(1)	Average Fixed Price(1)	Fair Value Asset (in thousands)(2)	Total Type (in thousands)(2)
Natural Gas – Fixed Price Swaps	2016(3)	13,656,600	$ 2.970	$ (425)	
	2017	48,127,700	$ 3.116	$ 958	
	2018	47,559,300	$ 2.959	$ 1,415	
					$ 1,948
Crude Oil – Fixed Price Swaps	2016(3)	301,900	$ 42.763	$ (1,856)	
	2017	1,057,900	$ 46.150	$ (5,367)	
	2018	893,500	$ 48.938	$ (3,683)	
					$ (10,906)
				Total net liabilities	$ (8,958)

(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 and natural gas put options are based on forward NYMEX natural gas prices, as applicable. Fair value of crude oil fixed price swaps are based on forward WTI crude oil prices, as applicable.
(3) The production volumes for 2016 include the remaining three months of 2016 beginning October 1, 2016.

Secured Hedge Facility

At September 30, 2016, we have a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as the ultimate general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, 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 its assets.

An event of default occurred under the secured hedging facility agreement upon our filing of voluntary petitions for relief under Chapter 11. The lenders under the secured hedge facility agreed to forbear from exercising remedies in respect of such event of default while the Chapter 11 Filings were pending and, upon occurrence of the effective date of the Plan contemplated by the Restructuring Support Agreement, such event of default is no longer be deemed to exist or to continue under the secured hedge facility.

In addition, it will be an event of default under our First Lien Credit Facility if we, as the ultimate general partner of the Drilling Partnerships, breach an obligation governed by the secured hedge facility, and the effect of such breach is to cause amounts owing under swap agreements governed by the secured hedge facility to become immediately due and payable.

NOTE 7 – FAIR VALUE OF FINANCIAL INSTRUMENTS

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We use a market approach fair value methodology to value our outstanding derivative contracts. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into the three level hierarchy (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of September 30, 2016 and December 31, 2015, all of our derivative financial instruments were classified as Level 2.

Information for financial instruments measured at fair value at September 30, 2016 and December 31, 2015 was as follows (in thousands):

Successor Derivatives, Fair Value, as of September 30, 2016	Level 1	Level 2	Level 3	Total
Assets, gross				
Commodity swaps	$ —	$8,324	$ —	$8,324
Total derivative assets, gross	—	8,324	—	8,324
Liabilities, gross				
Commodity swaps	—	(17,282)	—	(17,282)
Total derivative liabilities, gross	—	(17,282)	—	(17,282)
Total derivatives, fair value, net	$ —	$(8,958)	$ —	$(8,958)

Predecessor Derivatives, Fair Value, as of December 31, 2015	Level 1	Level 2	Level 3	Total
Assets, gross				
Commodity swaps	$ —	$355,329	$ —	$355,329
Commodity puts	—	2,393	—	2,393
Total derivatives, fair value, net	$ —	$357,722	$ —	$357,722

Other Financial Instruments

Our other current assets and liabilities on our condensed consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair value of our long-term debt at September 30, 2016, which consists of our First Lien Credit Facility and Second Lien Credit Facility, was $639.4 million compared with a carrying amount of $690.3 million. At September 30, 2016, 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

Management estimated the fair values of natural gas and oil properties transferred to our Predecessor upon liquidations of certain Drilling Partnerships (see Note 8) based on discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, our 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 are Level 3 measurements as they are based on unobservable inputs.

Management estimated the fair value of asset retirement obligations transferred to our Predecessor upon liquidations of certain Drilling Partnerships (see Note 4) based on discounted cash flow projections using our 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 assumed credit-adjusted risk-free interest rate. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

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

NOTE 8 – CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with ATLS. Except for our named executive officers, we do not directly employ any persons to manage or operate our business. These functions are provided by employees of ATLS and/or its affiliates. As of September 30, 2016 and December 31, 2015, we had a $5.5 million receivable and a $1.3 million payable, respectively, from/to 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/from affiliates in the 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.

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 $5.2 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 our Predecessor experienced a prolonged restructuring period as we perform all administrative and management functions for the Drilling Partnerships. On July 26, 2016, we adopted certain amendments to the Drilling Partnerships' partnership agreements, in accordance with our ability to amend the Drilling Partnerships' partnership agreements to cure an ambiguity in or correct or supplement any provision of the Drilling Partnerships' partnership agreements as may be inconsistent with any other provision, to provide that bankruptcy and insolvency events, such as the Chapter 11 Filings, with respect to the managing general partner will not cause the managing general partner to cease to serve as the managing general partner of the Drilling Partnerships nor cause the termination of the Drilling Partnerships.

We intend to continue to fund the Drilling Partnerships' operations and obligations, as necessary, until they are liquidated. Depending on commodity pricing and each of the Drilling Partnerships' reserves value, we expect to realize all outstanding receivables from the Drilling Partnerships' through the receipt of cash flows from their operations and/or the transfer of net assets and liabilities to us upon their liquidation. During the predecessor period from January 1, 2016 to August 31, 2016, our Predecessor recorded $7.2 million and $12.4 million of gas and oil properties and asset retirement obligations, respectively, transferred to our Predecessor as a result of certain Drilling Partnership liquidations. The gas and oil properties and asset retirement obligations were recorded at their fair values on the respective dates of the Drilling Partnerships' liquidation and transfer to our Predecessor (see Note 7) and resulted in a non-cash loss of $6.1 million, net of liquidation and transfer adjustments, for the predecessor period from January 1, 2016 through August 31, 2016, which was recorded in other income/(loss) in our Predecessor's condensed consolidated statements of operations.

On October 24, 2016, the Board of Directors of our subsidiary, Atlas Resources, LLC, approved our acquisition of properties in exchange for assuming all liabilities in connection with the liquidation of certain of our Drilling Partnerships. These acquisitions have an effective date of October 1, 2016. We estimate we will record approximately $31.0 million and $14.7 million of gas and oil properties and asset retirement obligations, respectively, which will result in an estimated non-cash gain of approximately $16.3 million, before any liquidation and transfer accounting adjustments, that will be recognized in the fourth quarter of 2016.

During the Predecessor periods from July 1, 2016 to August 31, 2016 and January 1, 2016 to August 31, 2016, we recognized a $10.9 million provision for losses on Drilling Partnership receivables related to the write down of certain receivables to their estimated net realizable values. As of September 30, 2016 and December 31, 2015, we had trade receivables of $0.6 million and a $6.6 million, respectively, from certain of the Drilling Partnerships', which were recorded in accounts receivable in the condensed consolidated balance sheets. As of September 30, 2016 and December 31, 2015, we had trade payables of $2.3 million and $3.0 million, respectively, to certain of the Drilling Partnerships', which were recorded in accounts payable in the 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. In addition, Anthem Securities, Inc. ("Anthem"), our wholly owned subsidiary, acted as dealer manager for AGP's private placement offering, which was completed in June 2015. As the dealer manager, Anthem received compensation from AGP equal to a maximum of 12% of the gross proceeds of the private placement offering as selling commissions, marketing efforts, and other issuance costs.

Anthem is currently acting as the dealer manager for AGP's issuance and sale in a continuous offering of up to a maximum agreement amount of 100,000,000 common units representing limited partner interests in AGP as further described in AGP's registration statement on Form S-1 (File No. 333-207537). AGP will pay Anthem (1) compensation equal to 3.00% of the gross proceeds of the offering (Anthem may reallow up to 1.50% of gross offering proceeds it receives as dealer manager fees to participating broker-dealers, but expects to reallow 1.25% of gross offering proceeds to participating broker-dealers); (2) 7.00% and 3.00% of aggregate gross proceeds from the sale of Class A common units and Class T common units, respectively, as sales commissions; (3) with respect to Class T common units, a distribution and unitholder servicing fee in the aggregate amount of 4.00% of the gross proceeds from the sale of Class T common units, which distribution and unitholder servicing fee will be withheld from cash distributions otherwise payable to the purchasers of Class T common units at a rate of $0.025 per quarter per unit. On November 2, 2016, AGP decided to temporarily suspend its current primary offering efforts in light of new regulations and the challenging fund raising environment until such time as market participants have had an opportunity to ascertain the impact of such issues.

As of September 30, 2016 and December 31, 2015, we had a $0.1 million receivable and $8.7 million payable, respectively, from/to AGP related to AGP's direct costs, indirect cost allocation and dealer manager costs, which was recorded in advances to/from affiliates in the condensed consolidated balance sheets.

NOTE 9 – COMMITMENTS AND CONTINGENCIES

General Commitments

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally, for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of September 30, 2016, our management believes that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

While our historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production revenue, subject to a limitation of the cumulative subordination previously recognized. For the Successor period September 1, 2016 through September 30, 2016, the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 and the three and nine months ended September 30, 2015, $0.2 million, $0.4 million, $1.0 million, $0.4 million and $1.5 million, respectively, of our gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses.

As of September 30, 2016, we are committed to expend approximately $4.3 million, principally on drilling and completion expenditures.

Legal Proceedings

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

NOTE 10 – INCOME TAXES

We account for income taxes under the asset and liability method pursuant to prevailing accounting literature. Under such literature, deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realization of deferred tax assets is assessed and, if not more-likely-than-not, a valuation allowance is recorded to write down the deferred tax assets to their net realizable value.

We recognize the financial statement benefit of a tax position after determining that the relevant tax authority would more likely than not sustain the position following an audit under guidance contained in FASB ASC 740. For tax positions meeting a more-likely-than-not threshold, the amount recognized in the consolidated financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. Our policy is to reflect interest and penalties related to uncertain tax positions as part of the income tax expense, when and if they become applicable. We have applied this methodology to all tax positions for which the statute of limitations remains open, and there are no additions, reductions or settlements in unrecognized tax benefits during the Successor period from September 1, 2016 to September 30, 2016. We have no material uncertain tax positions as of September 30, 2016.

We have evaluated the full impact of the restructuring pursuant to the pre-packaged plan of reorganization and believe the reorganization will be treated as a taxable exchange under the Internal Revenue Code. Accordingly, we will have an initial tax basis in the assets acquired equal to their respective fair market values immediately after the reorganization and no tax attributes will carryover to us as a result of the reorganization. In addition, as part of the reorganization, we have elected to be treated as a corporation for U.S. Federal and state income tax purposes.

For the Successor period September 1, 2016 to September 30, 2016, we generated an operating loss but did not recognize any income tax benefit. Management has determined uncertainties exist as to the future utilization of the operating loss carryforward; therefore, has recorded a full valuation allowance against our net deferred tax asset.

We are subject to income taxes in the U.S. federal jurisdiction and various states. Tax regulations within each jurisdiction are subject to the interpretations of the related tax laws and regulations and require significant judgment to apply. We are no longer subject to U.S. federal, state, and local, or non-U.S. income tax examinations by tax authorities for the years before 2013.

NOTE 11 – ISSUANCES OF UNITS

As of the Plan Effective Date, we had 5,416,667 shares of our common equity outstanding. Titan Management holds our Series A Preferred Share, which entitles Titan Management to 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. 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.

On September 1, 2016, we adopted the Titan Energy, LLC Management Incentive Plan (the "MIP") for the employees, directors and individual consultants of us and our affiliates. On October 26, 2016 the MIP was amended and restated to increase the number of shares that may be issued. The MIP permits the grant of options, phantom shares and restricted and unrestricted common shares, as well as dividend equivalent rights. Subject to adjustment in accordance with the MIP, a maximum of 655,555 common shares may be issued pursuant to awards under the MIP. Common Shares subject to forfeited awards or withheld to satisfy exercise prices or tax withholding obligations will again be available for delivery pursuant to other awards. The MIP has a term of 10 years and will be administered by the Board of Directors, which may delegate to a committee or the Company's chief executive officer. On September 1, 2016, 138,750 common shares from the MIP were issued and vested immediately as the service inception date was the date of the Chapter 11 Filings and the service completion date was the Plan Effective Date, resulting in $0.7 million of non-cash compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 to August 31, 2016. Also on September 1, 2016, 277,917 common shares from the MIP were issued and vest 33% on each of the next three anniversaries of the date of grant, resulting in $0.1 million of non-cash compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the

Successor period from September 1, 2016 to September 30, 2016. At September 30, 2016, we had $1.5 million in unrecognized compensation expense related to unvested common shares. The fair value of the common shares was determined in connection with our estimate of the equity value of the Successor utilizing the discounted cash flow method (see Notes 3 and 7).

On the Plan Effective Date, all of our Predecessor's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any distribution or consideration.

Our Predecessor had an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to its equity distribution agreement, our Predecessor sold from time to time through the Agents its common units representing limited partner interests of the Predecessor having an aggregate offering price of up to $100.0 million. Sales of its common units were made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the former trading market for its common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. Our Predecessor paid each of the Agents a commission, which in each case was not more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of its equity distribution agreement, our Predecessor sold common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of its common units to an Agent as principal was pursuant to the terms of a separate terms agreement between the Predecessor and such Agent. During the Predecessor period from July 1, 2016 through August 31, 2016, our Predecessor did not issue any common limited partner units under its equity distribution program. During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor issued 245,175 common limited partner units under its equity distribution program for net proceeds of $0.2 million, net of $4,000 in commissions and offering expenses paid. During the Predecessor three months ended September 30, 2015, our Predecessor issued 5,519,110 common limited partner units under its equity distribution program for net proceeds of $18.6 million, net of $0.3 million in commissions and offering expenses paid. During the Predecessor nine months ended September 30, 2015, our Predecessor issued 8,404,934 common limited partner units under its equity distribution program for net proceeds of $40.0 million, net of $1.0 million in commissions and offering expenses paid.

In August 2015, our Predecessor entered into a distribution agreement with MLV & Co. LLC (“MLV”), which it terminated and replaced in November 2015, when our Predecessor entered into a distribution agreement with MLV and FBR Capital Markets & Co. in which it sold its 8.625% Class D Cumulative Redeemable Perpetual Preferred Units (“Class D Preferred Units”) and Class E Cumulative Redeemable Perpetual Preferred Units (“Class E Preferred Units”). Under both the August 2015 ATM Agreement and the November 2015 ATM Agreement, our Predecessor did not issue any Class D Preferred units nor Class E Preferred Units under its preferred equity distribution program for the Predecessor period from January 1, 2016 through August 31, 2016. During the three and nine months ended September 30, 2015, our Predecessor issued 90,328 Class D Preferred Units and 1,083 Class E Preferred Units under its preferred equity distribution program for net proceeds of $1.0 million, net of $0.2 million in commissions and offering expenses paid.

In May 2015, in connection with the Arkoma Acquisition, our Predecessor issued 6,500,000 of its common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of $49.7 million. Our Predecessor used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under its Old First Lien Credit Facility.

In April 2015, our Predecessor issued 255,000 of its Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of $6.0 million.

On March 31, 2015, to partially pay its portion of a quarterly installment related to the Eagle Ford acquisition, our Predecessor issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit.

On July 31, 2016, our Predecessor’s 3,749,986 Class C Preferred Units that were issued to ATLS on July 31, 2013, were converted into 3,749,986 common units and the associated warrant issued to ATLS to purchase 562,497 of its common units expired.

On July 12, 2016, our Predecessor received notification from the New York Stock Exchange (“NYSE”) that the NYSE commenced proceedings to delist its common units as a result of our failure to comply with the continued listed standards set forth in Section 802.01C of the NYSE Listed Company Manual to maintain an average closing price of $1.00 per unit over a consecutive 30 day period. Our Predecessor’s Class D Preferred Units and Class E Preferred Units were also delisted from the NYSE. Our Predecessor’s common units, Class D Preferred Units, and Class E Preferred Units began trading on the OTC market on July 13, 2016 with the ticker symbol “ARPJ” for its common units, “ARPJP” for its Class D Preferred Units, and “ARPJN” for its Class E Preferred Units.

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

NOTE 12 – CASH DISTRIBUTIONS

We did not pay any distributions for the period from September 1, 2016 through September 30, 2016.

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.

While outstanding, our Predecessor's Class B Preferred Units received regular quarterly cash distributions equal to the greater of (i) $0.40 (or $0.1333 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. In July 2015, the remaining 39,654 of our Predecessor's Class B Preferred Units were converted into common limited partner units.

Our Predecessor's Class C Preferred Units received regular quarterly cash distributions equal to the greater of (i) $0.51 (or $0.17 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. On May 5, 2016, our Predecessor's Board of Directors elected to suspend our Predecessor's common unit and Class C preferred distributions, beginning with the month of March of 2016, due to the continued lower commodity price environment.

Our Predecessor paid quarterly distributions on its Class D Preferred Units at an annual rate of $2.15625 per unit, $0.5390625 per unit paid on a quarterly basis, or 8.625% of the $25.00 liquidation preference. Our Predecessor paid quarterly distributions on its Class E Preferred Units at an annual rate of $2.6875 per unit, or $0.671875 per unit on a quarterly basis, or 10.75% of the $25.00 liquidation preference. On June 16, 2016, our Predecessor's Board of Directors elected to suspend its quarterly distributions on its Class D Preferred Units and its Class E Preferred Units, beginning with the second quarter 2016 distribution, due to the continued lower commodity price environment. Our Predecessor's Class D Preferred Units and Class E Preferred Units accrued distributions of $3.4 million and $0.3 million, respectively, from April 15, 2016 through August 31, 2016. However, due to our Predecessor's distribution suspension and our Predecessor's recent Chapter 11 Filings, these amounts were not earned as the preferred units were cancelled without receipt of any consideration on the Plan Effective Date.

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid four monthly cash distributions totaling $5.1 million to its common limited partners ($0.0125 per unit per month); $2.5 million to its Preferred Class C limited partners ($0.0125 per unit per month); and $0.2 million to its General Partner Class A holder ($0.0125 per unit per month). During our Predecessor's nine months ended September 30, 2015, our Predecessor paid nine monthly cash distributions totaling $103.0 million to its common limited partners ($0.1966 per unit in both January and February 2015 and $0.1083 per unit in March through September 2015); $5.9 million to its Preferred Class C limited partners ($0.1966 per unit in both January and February 2015 and $0.17 per unit in March through September 2015); approximately $42,000 to its Preferred Class B limited partners ($0.1966 per unit in both January and February 2015 and $0.1333 per unit in March through July 2015); and $4.3 million to its General Partner Class A holder ($0.1966 per unit in both January and February 2015 and $0.1083 per unit in March through September 2015).

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling $4.4 million to its Class D Preferred units ($0.5390625 per unit) for the period October 15, 2015 through April 14, 2016. During our Predecessor's nine months ended September 30, 2015, our Predecessor paid three distributions totaling $6.3 million to its Class D Preferred units ($0.6169270 per unit for the period October 2, 2014 through January 14, 2015 and $0.539063 per unit for the period January 15, 2015 through July 14, 2015).

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling $0.3 million to its Class E Preferred units ($0.671875 per unit) for the period October 15, 2015 through April 14, 2016. During our Predecessor's nine months ended September 30, 2015, our Predecessor paid one $0.2 million distribution to its Class E Preferred units ($0.6793 per unit) for the period April 14, 2015 through July 14, 2015.

NOTE 13 – OPERATING SEGMENT INFORMATION

Our operations include and our predecessor's operations included three reportable operating segments. These operating segments reflect the way we manage and our predecessor managed our operations and make business decisions. Operating segment data for the periods indicated were as follows (in thousands):

	Successor	Predecessor	
	Period September 1 - 30, 2016	Period July 1 – August 31, 2016	Three Months Ended September 30, 2015
Gas and oil production:			
Revenues	$ 17,128	$ 42,433	$ 221,799
Operating costs and expenses	(10,522)	(19,872)	(41,591)
Depreciation, depletion and amortization expense	(5,817)	(16,512)	(37,079)
Asset impairment	—	—	(672,246)
Segment income (loss)	$ 789	$ 6,049	$ (529,117)
Well construction and completion:			
Revenues	$ 1,304	$ 18,383	$ 23,054
Operating costs and expenses	(1,134)	(15,985)	(20,046)
Segment income	$ 170	$ 2,398	$ 3,008
Other partnership management:(1)			
Revenues	$ 2,003	$ 3,870	$ 13,042
Operating costs and expenses	(1,205)	(2,448)	(4,871)
Depreciation, depletion and amortization expense	(204)	(6,766)	(3,384)
Segment income (loss)	$ 594	$ (5,344)	$ 4,787
Reconciliation of segment income (loss) to net loss:			
Segment income (loss):			
Gas and oil production	$ 789	$ 6,049	$ (529,117)
Well construction and completion	170	2,398	3,008
Other partnership management (1)	594	(5,344)	4,787
Total segment income (loss)	1,553	3,103	(521,322)
General and administrative expenses(2)	(4,931)	(17,166)	(13,978)
Interest expense(2)	(3,810)	(14,928)	(25,192)
Gain on early extinguishment of debt(2)	—	—	—
Gain (loss) on asset sales and disposal(2)	10	14	(362)
Reorganization items, net(2)	(353)	(16,614)	—
Other income (loss) (2)	—	(3,033)	—
Income tax expense(2)	—	—	—
Net loss	$ (7,531)	$ (48,624)	$ (560,854)
Reconciliation of segment revenues to total revenues:			
Gas and oil production	$ 17,128	$ 42,433	$ 221,799
Well construction and completion	1,304	$ 18,383	23,054
Other partnership management	2,003	$ 3,870	13,042
Total revenues	$ 20,435	$ 64,686	$ 257,895
Capital expenditures:			
Gas and oil production	$ 5,464	$ 5,529	$ 31,753
Other partnership management	(115)	496	639

Corporate and other	18	49	407
Total capital expenditures	$ 5,367	$ 6,074	$ 32,799

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	Successor	Predecessor	
	Period September1 - September 30, 2016	Period January 1 - August 31, 2016	Nine Months Ended September 30, 2015
Gas and oil production:			
Revenues	$ 17,128	$ 115,178	$ 501,949
Operating costs and expenses	(10,522)	(86,566)	(130,224)
Depreciation, depletion and amortization expense	(5,817)	(68,647)	(116,559)
Asset impairment	—	—	(672,246
Segment income (loss)	$ 789	$ (40,035)	$ (417,080)
Well construction and completion:			
Revenues	$ 1,304	$ 19,157	$ 63,665
Operating costs and expenses	(1,134)	(16,658)	(55,361)
Segment income	$ 170	$ 2,499	$ 8,304
Other partnership management:(1)			
Revenues	$ 2,003	$ 16,735	$ 31,995
Operating costs and expenses	(1,205)	(10,570)	(14,141)
Depreciation, depletion and amortization expense	(204)	(13,684)	(9,389)
Segment income (loss)	$ 594	$ (7,519)	$ 8,465
Reconciliation of segment income (loss) to net loss:			
Segment income (loss):			
Gas and oil production	$ 789	$ (40,035)	$ (417,080)
Well construction and completion	170	2,499	8,304
Other partnership management (1)	594	(7,519)	8,465
Total segment income (loss)	1,553	(45,055)	(400,311)
General and administrative expenses(2)	(4,931)	(58,004)	(44,400)
Interest expense(2)	(3,810)	(74,587)	(75,105)
Gain on early extinguishment of debt(2)	—	26,498	—
Gain (loss) on asset sales and disposal(2)	10	(479)	(276)
Reorganization items, net(2)	(353)	(16,614)	—
Other income (loss)(2)	—	(9,189)	—
Income tax expense(2)	—	—	—
Net loss	$ (7,531)	$ (177,430)	$ (520,092)
Reconciliation of segment revenues to total revenues:			
Gas and oil production	$ 17,128	$ 115,178	$ 501,949
Well construction and completion	1,304	19,157	63,665
Other partnership management	2,003	16,735	31,995
Total revenues	$ 20,435	$ 151,070	$ 597,609
Capital expenditures:			
Gas and oil production	$ 5,464	$ 22,684	$ 87,986
Other partnership management	(115)	2,046	13,433
Corporate and other	18	164	871
Total capital expenditures	$ 5,367	$ 24,894	$ 102,290

(1) Includes revenues and expenses from well services, gathering and processing, administration and oversight, and other, net that do not meet the quantitative threshold for reporting segment information.

(2)

Gain (loss) on asset sales and disposal, general and administrative expenses, reorganization items, net, gain on early extinguishment of debt, interest expense and income tax expense have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented.

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	Successor September 30, 2016	Predecessor December 31, 2015
Balance sheet:		
Goodwill:		
Well construction and completion	$ —	$ 6,389
Other partnership management	—	7,250
Total goodwill	$ —	$ 13,639
Total assets:		
Gas and oil production	$ 792,241	$ 1,551,450
Well construction and completion	730	27,039
Other partnership management	9,681	66,641
Corporate and other	41,979	54,819
Total assets	$ 844,631	$ 1,699,949

NOTE 14 – SUBSEQUENT EVENTS

Partnership Liquidations. On October 24, 2016, the Board of Directors of our subsidiary, Atlas Resources, LLC, approved our acquisition of properties in exchange for assuming all liabilities in connection with the liquidation of certain of our Drilling Partnerships. These acquisitions have an effective date of October 1, 2016 (see Note 8).

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

BUSINESS OVERVIEW

We are an independent developer and producer of natural gas, crude oil and natural gas liquids ("NGL") with operations in basins across the United States. 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. Unless the context otherwise requires, references to "Titan Energy, LLC," "Titan," "the Company," "we," "us," "our" and "our company," refer to Titan Energy, LLC and our consolidated subsidiaries (and its 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 ("Atlas Energy Group" or "ATLS"; OTC: 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.

FINANCIAL PRESENTATION

Our consolidated balance sheet at September 30, 2016, and the consolidated statements of operations for the period from September 1, 2016 through September 30, 2016 include our accounts and the accounts of our wholly-owned subsidiaries. The consolidated balance sheet at December 31, 2015, and the consolidated statements of operations for the period from July 1, 2016 through August 31, 2016, the period from January 1, 2016 through August 31, 2016 and the three and nine months ended September 30, 2015 include our predecessor's accounts and the accounts of its wholly-owned subsidiaries. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the consolidation of the financial statements.

RECENT DEVELOPMENTS

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, Atlas Resource Partners, L.P. ("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 (i) lenders holding 100% of ARP's senior secured revolving credit facility (the "First Lien Lenders"), (ii) lenders holding 100% of ARP's second lien term loan (the "Second Lien Lenders") and (iii) holders (the "Consenting Noteholders" and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that become party to the Restructuring Support Agreement, the "Restructuring Support Parties") of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the "7.75% Senior Notes") and the 9.25% Senior Notes due 2021 (the "9.25% Senior Notes" and, together with the 7.75% Senior Notes, the "Notes") of ARP's subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the "Issuers"). Under the Restructuring Support Agreement, the Restructuring Support Parties agreed, subject to certain terms and conditions, to support ARP's restructuring (the "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 of the United States Bankruptcy Code ("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."

ARP operated its businesses as "debtors in possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords were unimpaired by the Plan and were satisfied in full in the ordinary course of business, and ARP's existing trade contracts and terms were maintained. To assure ordinary course operations, ARP obtained interim approval from the Bankruptcy Court on a variety of "first day" motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to ARP, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

On September 1, 2016, (the "Plan Effective Date"), pursuant to the Plan, the following occurred:

- the 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 (Refer to Note 5 – Debt for further information regarding terms and provisions).
- the 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 (Refer to Note 5 – Debt for further information regarding terms and provisions). In addition, the Second Lien Lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.
- Holders of the Notes, in exchange for 100% of the $668 million aggregate principal amount of 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.
- 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
- all of ARP's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.
- Titan Management LLC ("Titan Management"), a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive to 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. Four of the seven initial members of the board of directors of us were designated by Titan Management (the "Titan Class A Directors"). For so long as Titan Management holds the Series A Preferred Share, the Class A Directors will be appointed by a majority of the 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.

First Lien Credit Facility

On September 1, 2016, we entered into a $440 million third amended and restated first lien credit agreement with Wells Fargo Bank, National Association ("Wells Fargo"), as administrative agent, and the lenders party thereto (the "First Lien Credit Facility"). (See "Credit Facilities" below).

Second Lien Credit Facility

On September 1, 2016, we entered into an amended and restated second lien credit agreement with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto (the "Second Lien Credit Facility") for an aggregate principal amount of $252.5 million maturing on February 23, 2020. (See "Credit Facilities" below).

Common Equity

As of the Plan Effective Date, we had 5,416,667 common shares outstanding. (See "Issuance of Units" below).

Liquidation of Drilling Partnerships

On October 24, 2016, the Board of Directors of our subsidiary, Atlas Resources, LLC, approved our acquisition of properties in exchange for assuming all liabilities in connection with the liquidation of certain of our Drilling Partnerships. These acquisitions have an effective date of October 1, 2016. We estimated we will record approximately $31.0 million and $14.7 million of gas and oil properties and asset retirement obligations, respectively, which will result in an estimated non-cash gain of approximately $16.3 million, before any liquidation and transfer accounting adjustments, that will be recognized in the fourth quarter of 2016.

Liquidation of Hedge Portfolio

On July 27, 2016, pursuant to the Restructuring Support Agreement, we completed the sale of certain of our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under ARP’s Old First Lien Credit Facility.

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 through the third quarter of 2016. 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, our ability to make payments on our debts and our ability to make distributions to our unitholders, including ATLS, 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 and results of operations on and after the Effective Date are not comparable to our financial condition and results of operations prior to the Plan Effective Date. For comparative purposes, we believe that reporting and analyzing the successor period results for the period from September 1, 2016 through September 30, 2016 combined with the predecessor period results from the period July 1, 2016 through August 31, 2016 and the successor period results for the period from September 1, 2016 through September 30, 2016 combined with the predecessor period results from the period January 1, 2016 through August 31, 2016 compared with the three and nine months ended September 30, 2016, respectively, provides a reasonable basis of comparison and is consistent with how management reviews our results.

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various plays throughout the United States. Through September 30, 2016, 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;
- Coal-bed Methane producing natural gas assets in (1) the Raton Basin in northern New Mexico and the Black Warrior Basin in central Alabama, acquired in 2013; (2) the Central Appalachia Basin in West Virginia and Virginia, acquired in 2014, and; (3) the Arkoma Basin in eastern Oklahoma, acquired in 2015.
- the Rangely field in northwest Colorado, a mature tertiary CO2 flood with low-decline oil production, where we have a 25% non-operated net working interest position which we acquired on June 30, 2014;
- the Appalachia Basin assets, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region; the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; and the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile;

- the Barnett Shale and Marble Falls play, both in the Fort Worth Basin in northern Texas. The Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil.
- the Mid-Continent assets, including Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area, and the Niobrara Shale assets in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

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 combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015:

	Successor Period September 1- September 30, 2016	Predecessor Period July 1- August 31, 2016	Combined Three Months Ended September 30, 2016	Predecessor Three Months Ended September 30, 2015
Gross wells drilled(3):				
Barnett/Marble Falls	—	—	—	—
Eagle Ford	—	2	2	13
Mississippi Lime	—	—	—	—
Total	—	2	2	13
Net wells drilled(1):				
Barnett/Marble Falls	—	—	—	—
Eagle Ford	—	2	2	4
Mississippi Lime	—	—	—	—
Total	—	2	2	4
Gross wells turned in line(2)(3):				
Appalachia-Utica	—	—	—	—
Barnett/Marble Falls	—	—	—	—
Eagle Ford	4	—	4	1
Mississippi Lime	—	—	—	2
Total	4	—	4	3
Net wells turned in line(1)(2)(3):				
Appalachia-Utica	—	—	—	—
Barnett/Marble Falls	—	—	—	—
Eagle Ford	1	—	1	1
Mississippi Lime	—	—	—	2
Total	1	—	1	3

	Successor Period September 1- September 30, 2016	Predecessor Period January 1- August 31, 2016	Combined Nine Months Ended September 30,	Predecessor Nine Months Ended September 30, 2015

			2016	
Gross wells drilled(3):				
Barnett/Marble Falls	—	—	—	3
Eagle Ford	—	2	2	13
Mississippi Lime	—	—	—	4
Total	—	2	2	20
Net wells drilled(1):				
Barnett/Marble Falls	—	—	—	2
Eagle Ford	—	2	2	4
Mississippi Lime	—	—	—	3
Total	—	2	2	9
Gross wells turned in line(2)(3):				
Appalachia-Utica	—	—	—	4
Barnett/Marble Falls	—	—	—	14
Eagle Ford	4	—	4	3
Mississippi Lime	—	—	—	13
Total	4	—	4	34
Net wells turned in line(1)(2)(3):				
Appalachia-Utica	—	—	—	1
Barnett/Marble Falls	—	—	—	4
Eagle Ford	1	—	1	2
Mississippi Lime	—	—	—	6
Total	1	—	1	13

(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.

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(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 combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015; there were no gross or net dry wells within our operating areas during the combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015.

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 the combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015:

	Successor	Predecessor	Combined	Predecessor
	Period September 1, – September 30, 2016	Period July 1, – August 31, 2016	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015
Production volumes per day:(1)(2)				
Appalachia:(3)				
Natural gas (Mcfd)	28,313	29,888	29,375	36,824
Oil (Bpd)	238	245	243	341
NGLs (Bpd)	357	312	326	342
Total (Mcfed)	31,879	33,230	32,790	40,922
Coal-bed Methane:(3)				
Natural gas (Mcfd)	114,030	114,100	114,077	128,560
Oil (Bpd)	—	—	—	—
NGLs (Bpd)	—	—	—	—
Total (Mcfed)	114,030	114,100	114,077	128,560
Barnett/Marble Falls:				
Natural gas (Mcfd)	30,992	31,034	31,020	43,685
Oil (Bpd)	167	177	174	495
NGLs (Bpd)	1,163	1,159	1,161	1,898
Total (Mcfed)	38,972	39,053	39,026	58,043
Rangely:				
Natural gas (Mcfd)	—	—	—	—
Oil (Bpd)	2,229	2,214	2,219	2,390
NGLs (Bpd)	232	242	238	248
Total (Mcfed)	14,766	14,736	14,746	15,829
Eagle Ford:				
Natural gas (Mcfd)	423	457	446	313
Oil (Bpd)	1,025	1,028	1,027	1,183
NGLs (Bpd)	88	95	93	65
Total (Mcfed)	7,102	7,197	7,166	7,803
Mid-Continent:(3)				
Natural gas (Mcfd)	3,516	3,460	3,479	7,032
Oil (Bpd)	132	148	143	433
NGLs (Bpd)	284	281	282	569
Total (Mcfed)	6,012	6,034	6,027	13,040
Total production volumes per day:				
Natural gas (Mcfd)	177,274	178,940	178,397	216,414
Oil (Bpd)	3,791	3,814	3,806	4,842

NGLs (Bpd)	2,124	2,088	2,100	3,121
Total (Mcfed)	212,762	214,350	213,832	264,196
Total production:(1)(2)				
Natural gas (MMcf)	5,318	11,094	16,412	19,910
Oil (000's Bbls)	114	236	350	446
NGLs (000's Bbls)	64	129	193	287
Total (MMcfe)	6,383	13,290	19,673	24,306

	Successor Period September 1, – September 30, 2016	Predecessor Period January 1, – August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
Production volumes per day:(1)(2)				
Appalachia:(3)				
Natural gas (Mcfd)	28,313	30,925	30,639	35,410

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Oil (Bpd)	238	292	286	362
NGLs (Bpd)	357	307	313	282
Total (Mcfed)	31,879	34,522	34,233	39,273
Coal-bed Methane:(3)				
Natural gas (Mcfd)	114,030	117,491	117,112	131,314
Oil (Bpd)	—	—	—	—
NGLs (Bpd)	—	—	—	—
Total (Mcfed)	114,030	117,491	117,112	131,314
Barnett/Marble Falls:				
Natural gas (Mcfd)	30,992	33,696	33,401	46,868
Oil (Bpd)	167	253	244	625
NGLs (Bpd)	1,163	1,298	1,283	2,088
Total (Mcfed)	38,972	43,002	42,562	63,144
Rangely:				
Natural gas (Mcfd)	—	—	—	—
Oil (Bpd)	2,229	2,287	2,281	2,380
NGLs (Bpd)	232	244	243	254
Total (Mcfed)	14,766	15,187	15,141	15,805
Eagle Ford:				
Natural gas (Mcfd)	423	437	435	337
Oil (Bpd)	1,025	1,212	1,192	1,410
NGLs (Bpd)	88	91	91	71
Total (Mcfed)	7,102	8,257	8,131	9,219
Mid-Continent:(3)				
Natural gas (Mcfd)	3,516	4,413	4,315	7,229
Oil (Bpd)	132	179	174	443
NGLs (Bpd)	284	356	348	572
Total (Mcfed)	6,012	7,624	7,448	13,322
Total production volumes per day:				
Natural gas (Mcfd)	177,274	186,962	185,902	221,159
Oil (Bpd)	3,791	4,224	4,177	5,220
NGLs (Bpd)	2,124	2,296	2,277	3,266
Total (Mcfed)	212,762	226,083	224,626	272,077
Total production:(1)(2)				
Natural gas (MMcf)	5,318	45,619	50,937	60,376
Oil (000's Bbls)	114	1,031	1,144	1,425
NGLs (000's Bbls)	64	560	624	892
Total (MMcfe)	6,383	55,164	61,547	74,277

(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) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the

Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and the Niobrara Shale (northeastern Colorado).

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Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015 along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

	Successor	Predecessor	Combined	Predecessor
	Period September 1 – September 30, 2016	Period July 1 – August 31, 2016	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015
Production revenues (in thousands):[1]				
Appalachia:[2]				
Natural gas revenue	$ 1,008	$ 3,159	$ 4,167	$ 3,877
Oil revenue	326	484	810	2,094
Natural gas liquids revenue	64	99	163	43
Total revenues	$ 1,398	$ 3,742	$ 5,140	$ 6,014
Coal-bed Methane:[2]				
Natural gas revenue	$ 9,487	$ 21,546	$ 31,033	$ 42,237
Oil revenue	—	—	—	—
Natural gas liquids revenue	—	—	—	—
Total revenues	$ 9,487	$ 21,546	$ 31,033	$ 42,237
Barnett/Marble Falls:				
Natural gas revenue	$ 1,878	$ 4,615	$ 6,493	$ 10,400
Oil revenue	199	341	540	602
Natural gas liquids revenue	468	799	1,267	2,339
Total revenues	$ 2,545	$ 5,755	$ 8,300	$ 13,341
Rangely:				
Natural gas revenue	$ —	$ —	$ —	$ —
Oil revenue	2,837	4,381	7,218	17,181
Natural gas liquids revenue	214	452	666	864
Total revenues	$ 3,051	$ 4,833	$ 7,884	$ 18,045
Eagle Ford:				
Natural gas revenue	$ 35	$ 92	$ 127	$ 73
Oil revenue	1,306	1,960	3,266	7,596
Natural gas liquids revenue	45	86	131	69
Total revenues	$ 1,386	$ 2,138	$ 3,524	$ 7,738
Mid-Continent:[2]				
Natural gas revenue	$ 287	$ 637	$ 924	$ 1,332
Oil revenue	163	283	446	1,381
Natural gas liquids revenue	141	271	412	646
Total revenues	$ 591	$ 1,191	$ 1,782	$ 3,359

Total production revenues:				
Natural gas revenue	$ 12,695	$ 30,049	$ 42,744	$ 57,919
Oil revenue	4,831	7,449	12,280	28,854
Natural gas liquids revenue	932	1,707	2,639	3,961
Total revenues	$ 18,458	$ 39,205	$ 57,663	$ 90,734
Average sales price:				
Natural gas (per Mcf):(3)				
Total realized price, after hedge(4) (1)	$ 2.58	$ 2.95	$ 2.86	$ 3.30
Total realized price, before hedge(4)	$ 2.48	$ 2.43	$ 2.44	$ 2.28
Oil (per Bbl):(3)				
Total realized price, after hedge(1)	$ 40.30	$ 41.22	$ 41.38	$ 88.42
Total realized price, before hedge	$ 42.48	$ 41.77	$ 42.00	$ 43.25
Natural gas liquids (per Bbl):(3)				
Total realized price, after hedge(1)	$ 14.63	$ 13.18	$ 13.66	$ 21.42
Total realized price, before hedge	$ 14.63	$ 13.18	$ 13.66	$ 11.01
Production costs (per Mcfe):(2) (3)				

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	Successor Period September 1 – September 30, 2016	Predecessor Period July 1 – August 31, 2016	Combined Three Months Ended September 30, 2016	Predecessor Three Months Ended September 30, 2015
Appalachia:				
Lease operating expenses(5)	$ 0.68	$ 0.65	$ 0.66	$ 0.92
Production taxes	0.05	0.06	0.06	0.06
Transportation and compression	0.29	0.22	0.24	0.23
	$ 1.02	$ 0.93	$ 0.96	$ 1.21
Coal-bed Methane:				
Lease operating expenses	$ 1.04	$ 0.95	$ 0.98	$ 1.06
Production taxes	0.24	0.21	0.22	0.20
Transportation and compression	0.19	0.18	0.18	0.32
	$ 1.46	$ 1.35	$ 1.39	$ 1.58
Barnett/Marble Falls:				
Lease operating expenses	$ 0.81	$ 0.72	$ 0.75	$ 1.30
Production taxes	0.22	0.21	0.21	0.17
Transportation and compression	0.22	0.24	0.23	0.15
	$ 1.25	$ 1.17	$ 1.20	$ 1.62
Rangely:				
Lease operating expenses	$ 4.59	$ 4.22	$ 4.34	$ 4.01
Production taxes	0.62	0.60	0.61	0.56
Transportation and compression	0.01	0.01	0.01	—
	$ 5.22	$ 4.82	$ 4.95	$ 4.57
Eagle Ford:				
Lease operating expenses	$ 2.03	$ 1.58	$ 1.73	$ 2.01
Production taxes	0.49	0.48	0.49	0.33
Transportation and compression	0.14	0.16	0.15	0.06
	$ 2.66	$ 2.23	$ 2.37	$ 2.40
Mid-Continent:				
Lease operating expenses	$ 2.14	$ 1.67	$ 1.83	$ 1.22
Production taxes	0.12	0.08	0.09	0.06
Transportation and compression	0.30	0.29	0.30	0.28
	$ 2.56	$ 2.04	$ 2.21	$ 1.56
Total production costs:				
Lease operating expenses(5)	$ 1.25	$ 1.13	$ 1.17	$ 1.30
Production taxes	0.24	0.22	0.23	0.19
Transportation and compression	0.20	0.19	0.19	0.24
	$ 1.69	$ 1.54	$ 1.59	$ 1.74

	Successor Period	Predecessor Period January 1 –	Combined Nine	Predecessor Nine

	September 1 – September 30, 2016	August 31, 2016	Months Ended September 30, 2016	Months Ended September 30, 2015
Production revenues (in thousands):[1]				
Appalachia:[2]				
Natural gas revenue	$ 1,008	$ 10,838	$ 11,846	$ 12,775
Oil revenue	326	3,443	3,769	6,780
Natural gas liquids revenue	64	280	344	477
Total revenues	$ 1,398	$ 14,561	$ 15,959	$ 20,032
Coal-bed Methane:[2]				
Natural gas revenue	$ 9,487	$ 66,899	$ 76,386	$ 131,212
Oil revenue	—	—	—	—
Natural gas liquids revenue	—	—	—	—
Total revenues	$ 9,487	$ 66,899	$ 76,386	$ 131,212

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	Successor Period September 1 – September 30, 2016	Predecessor Period January 1 – August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
Barnett/Marble Falls:				
Natural gas revenue	$ 1,878	$ 9,680	$ 11,558	$ 32,587
Oil revenue	199	1,113	1,312	5,043
Natural gas liquids revenue	468	2,850	3,318	8,058
Total revenues	$ 2,545	$ 13,643	$ 16,188	$ 45,688
Rangely:				
Natural gas revenue	$ —	$ —	$ —	$ —
Oil revenue	2,837	23,815	26,652	51,787
Natural gas liquids revenue	214	1,557	1,771	2,981
Total revenues	$ 3,051	$ 25,372	$ 28,423	$ 54,768
Eagle Ford:				
Natural gas revenue	$ 35	$ 298	$ 333	$ 340
Oil revenue	1,306	14,622	15,928	28,840
Natural gas liquids revenue	45	305	350	253
Total revenues	$ 1,386	$ 15,225	$ 16,611	$ 29,433
Mid-Continent:(2)				
Natural gas revenue	$ 287	$ 1,508	$ 1,795	$ 4,094
Oil revenue	163	726	889	4,650
Natural gas liquids revenue	141	1,160	1,301	2,366
Total revenues	$ 591	$ 3,394	$ 3,985	$ 11,110
Total production revenues:				
Natural gas revenue	$ 12,695	$ 89,223	$ 101,918	$ 181,008
Oil revenue	4,831	43,719	48,550	97,100
Natural gas liquids revenue	932	6,152	7,084	14,135
Total revenues	$ 18,458	$ 139,094	$ 157,552	$ 292,243
Average sales price:				
Natural gas (per Mcf):(3)				
Total realized price, after hedge(4) (1)	$ 2.58	$ 2.03	$ 3.26	$ 3.41
Total realized price, before hedge(4)	$ 2.48	$ 1.91	$ 1.97	$ 2.32
Oil (per Bbl):(3)				
Total realized price, after hedge(1)	$ 40.30	$ 70.38	$ 67.39	$ 83.99
Total realized price, before hedge	$ 42.48	$ 36.94	$ 37.49	$ 46.74
Natural gas liquids (per Bbl):(3)				
Total realized price, after hedge(1)	$ 14.63	$ 10.98	$ 11.35	$ 22.17
Total realized price, before hedge	$ 14.63	$ 10.98	$ 11.35	$ 13.00
Production costs (per Mcfe):(2) (3)				
Appalachia:				
Lease operating expenses(5)	$ 0.68	$ 0.72	$ 0.71	$ 1.02
Production taxes	0.05	0.06	0.06	0.06
Transportation and compression	0.29	0.22	0.23	0.27

	$ 1.02	$ 1.00	$ 1.00	$ 1.36

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	Successor Period September 1 – September 30, 2016	Predecessor Period January 1 – August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
Coal-bed Methane:				
Lease operating expenses	$ 1.04	$ 0.98	$ 0.99	$ 1.05
Production taxes	0.24	0.17	0.18	0.21
Transportation and compression	0.19	0.25	0.24	0.33
	$ 1.46	$ 1.40	$ 1.41	$ 1.60
Barnett/Marble Falls:				
Lease operating expenses	$ 0.81	$ 0.84	$ 0.84	$ 1.33
Production taxes	0.22	0.18	0.19	0.17
Transportation and compression	0.22	0.24	0.24	0.10
	$ 1.25	$ 1.27	$ 1.27	$ 1.59
Rangely:				
Lease operating expenses	$ 4.59	$ 4.33	$ 4.35	$ 4.23
Production taxes	0.62	0.59	0.59	0.51
Transportation and compression	0.01	0.01	0.01	—
	$ 5.22	$ 4.92	$ 4.95	$ 4.74
Eagle Ford:				
Lease operating expenses	$ 2.03	$ 1.71	$ 1.74	$ 1.88
Production taxes	0.49	0.43	0.44	0.34
Transportation and compression	0.14	0.13	0.13	0.08
	$ 2.66	$ 2.27	$ 2.31	$ 2.30
Mid-Continent:				
Lease operating expenses	$ 2.14	$ 1.60	$ 1.65	$ 1.41
Production taxes	0.12	0.07	0.07	0.07
Transportation and compression	0.30	0.30	0.30	0.27
	$ 2.56	$ 1.97	$ 2.02	$ 1.76
Total production costs:				
Lease operating expenses(5)	$ 1.25	$ 1.19	$ 1.19	$ 1.34
Production taxes	0.24	0.19	0.20	0.20
Transportation and compression	0.20	0.23	0.22	0.24
	$ 1.69	$ 1.60	$ 1.61	$ 1.78

(1) Production revenue excludes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015 (see Item 1: "Financial Statements (Unaudited) – Note 6"). Cash settlements on commodity derivative contracts excluded from production revenues consisted of $4.7 million and $6.8 million for natural gas and ($0.4) million and $10.5 million for oil for the combined three months ended September 30, 2016 and three months ended September 30, 2015, respectively; $63.2 million and $21.4 million for natural gas and $26.1 million and $22.6 million for oil for the combined nine months ended September 30, 2016 and the nine months ended September 30, 2015, respectively. Cash settlements on natural gas liquids contracts excluded from production

revenues consisted of $2.2 million and $5.6 million for the three and nine months ended September 30, 2015, respectively.

(2) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and Niobrara Shale (northeastern Colorado).

(3) "Mcf" represents thousand cubic feet; "Mcfe" represents thousand cubic feet equivalents; and "Bbl" represents barrels.

(4) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015. Including the effect of this subordination, the average realized gas sales price was $2.74 per Mcf ($2.35 per Mcf before the effects of financial hedging) and $3.25 per Mcf ($2.23 per Mcf before the effects of financial hedging) for the combined three months ended September 30, 2016 and the three months ended September 30, 2015, respectively, and $3.19 per Mcf ($1.90 per Mcf before the effects of financial hedging) and $3.35 per Mcf ($2.27 per Mcf before the effects of financial hedging) for the combined nine months ended September 30, 2016 and the nine months ended September 30, 2015, respectively.

(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 the combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015. Including the effects of these costs, Appalachia lease operating expenses were $0.38 per Mcfe ($0.68 per Mcfe for total production costs) and $0.76 per Mcfe ($1.06 per Mcfe for total production costs) for the combined three months ended September 30, 2016 and the three months ended September 30, 2015, respectively, and $0.48 per Mcfe ($0.77 per Mcfe for total production costs) and $0.86 per Mcfe ($1.20 per Mcfe for total production costs) for the combined nine months ended September 30, 2016 and the three months ended September 30, 2015, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $1.13 per Mcfe ($1.54 per Mcfe for total production costs) and $1.28 per Mcfe ($1.71 per Mcfe for total production costs) for the combined three months ended September 30, 2016 and the three months ended September 30, 2015, respectively, and $1.16 per Mcfe ($1.58 per Mcfe for total production costs) and $1.32 per Mcfe ($1.75 per Mcfe for total production costs) for the combined nine months ended September 30, 2016 and the nine months ended September 30, 2015, respectively.

(in thousands)	Successor Period September 1 – September 30, 2016	Predecessor Period July 1 – August 31, 2016	Combined Three Months Ended September 30, 2016	Predecessor Three Months Ended September 30, 2015
Gas and oil production revenues	$ 18,458	$ 39,205	$ 57,663	$ 90,734
Gas and oil production costs	$ (10,522)	$ (19,872)	$ (30,394)	$ (41,591)

(in thousands)	Successor Period September 1 – September 30, 2016	Predecessor Period January 1 – August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
Gas and oil production revenues	$ 18,458	$ 139,094	$ 157,552	$ 292,243
Gas and oil production costs	$ (10,522)	$ (86,566)	$ (97,088)	$ (130,224)

The $33.1 million decrease in gas and oil production revenues during the combined three months ended September 30, 2016 as compared to the prior year period consisted of an $11.2 million decrease attributable to our Coal-bed Methane operations, a $10.2 million decrease associated with our Rangely operations, a $5.0 million decrease attributable to our Barnett Shale/Marble Falls operations, a $4.2 million decrease attributable to our Eagle Ford operations, a $1.6 million decrease attributable to our Mid-Continent operations and a $0.9 million decrease attributable to our Appalachia operations. Our gas and oil production revenue decreases in all operating areas were attributed to lower production volumes and decreases in natural gas and oil prices compared to the prior year period.

The $134.7 million decrease in gas and oil production revenues during the combined nine months ended September 30, 2016 as compared to the prior year period consisted of a $54.8 million decrease attributable to our Coal-bed Methane operations, a $29.5 million decrease attributable to our Barnett Shale/Marble Falls operations, a $26.4 million decrease associated with our Rangely operations, a $12.8 million decrease attributable to our Eagle Ford operations, a $7.1 million decrease attributable to our Mid-Continent operations and a $4.1 million decrease attributable to our Appalachia operations. Our gas and oil production revenue decreases in all operating areas were attributed to lower production volumes and decreases in commodity prices compared to the prior year period.

The $11.2 million decrease in gas and oil production expenses during the combined three months ended September 30, 2016 as compared to the prior year period primarily consisted of a $4.4 million decrease attributable to our Barnett Shale/Marble Falls operations, a $4.2 million decrease attributable to our Coal-bed Methane operations, a $1.9 million decrease attributable to our Appalachia operations, a $0.6 million decrease attributable to our Mid-Continent operations and a $0.2 million decrease attributable to our Eagle Ford operations, partially offset by a $0.1 million increase attributable to our Rangely operations. Total production costs per Mcfe decreased between the periods primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

The $33.1 million decrease in gas and oil production expenses during the combined nine months ended September 30, 2016 as compared to the prior year period primarily consisted of a $12.7 million decrease attributable to our Barnett Shale/Marble Falls operations, an $11.9 million decrease attributable to our Coal-bed Methane operations, a $5.7 million decrease attributable to our Appalachia operations, a $2.3 million decrease attributable to our Mid-Continent operations and a $0.6 million decrease attributable to our Eagle Ford operations, partially offset by a $0.1 million increase attributable to our Rangely operations. Total production costs per Mcfe decreased between the periods primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling Partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for Drilling Partnerships we sponsor. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill. The following table presents the amounts of Drilling Partnership investor capital raised and deployed, as well as sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Successor	Predecessor	Combined	Predecessor
	Period September 1 – September 30, 2016	Period July 1 – August 31, 2016	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015
Drilling partnership investor capital:				
Raised	$ —	$ —	$ —	$ 24,954
Deployed	$ 1,304	$ 18,383	$ 19,687	$ 23,054
Average construction and completion:				
Revenue per well	$ 6,520	$ 5,407	$ 5,469	$ 7,204
Cost per well	(5,670)	(4,701)	(4,755)	(6,264)
Gross profit per well	$ 850	$ 706	$ 714	$ 940
Gross profit margin	$ 170	$ 2,398	$ 2,568	$ 3,008
Partnership net wells associated with revenue recognized(1):				
Appalachia - Utica	—	—	—	—
Marble Falls	—	—	—	—
Eagle Ford	—	3	—	3
Mississippi Lime	—	—	—	—
Total	—	3	—	3

	Successor	Predecessor	Combined	Predecessor
	Period September 1 – September 30, 2016	Period January 1 – August 31, 2016	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Drilling partnership investor capital:				
Raised	$ —	$ —	$ —	$ 24,954
Deployed	$ 1,304	$ 19,157	$ 20,461	$ 63,665

Average construction and completion:				
Revenue per well	$ 6,520	$ 5,252	$ 5,848	$ 3,942
Cost per well	(5,670)	(4,567)	(5,086)	(3,428)
Gross profit per well	$ 850	$ 685	$ 762	$ 514
Gross profit margin	$ 170	$ 2,499	$ 2,669	$ 8,304
Partnership net wells associated with revenue recognized[1]:				
Appalachia - Utica	—	—	—	2
Marble Falls	—	—	—	5
Eagle Ford	—	4	4	4
Mississippi Lime	—	—	—	5
Total	—	4	4	16

(1) Consists of Drilling Partnership net wells for which well construction and completion revenue was recognized on a percentage of completion basis.

The $0.4 million and $5.6 million decreases in well construction and completion gross profit margin during the combined three and nine month periods ended September 30, 2016, respectively, as compared to the respective prior year period were due to decreases in the number of partnership wells for which completion activities were being performed related to timing and the economics of such activities during the challenging commodity price environment along with a downward revision to our estimated total costs to

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complete wells, which resulted in unfavorable adjustments to our gross profit margin recognized on our percentage of completion basis for the wells in progress.

Administration and Oversight

	Successor Period September 1 – September 30, 2016	Predecessor Period July 1 – August 31, 2016	Combined Three Months Ended September 30, 2016	Predecessor Three Months Ended September 30, 2015
(in thousands)				
Administration and oversight revenues	$ 147	$ 313	$ 460	$ 5,495

	Successor Period September 1 – September 30, 2016	Predecessor Period January 1 – August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
(in thousands)				
Administration and oversight revenues	$ 147	$ 1,263	$ 1,410	$ 7,301

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our Drilling Partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the Drilling Partnerships, such as those in the Marble Falls play, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales. The following table presents the number of gross and net development wells we drilled for our Drilling Partnerships during the combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015. There were no exploratory wells drilled during the combined three and nine months ended September 30, 2016 and the three and nine months ended September 30, 2015:

	Successor Period September 1 – September 30, 2016	Predecessor Period July 1 – August 31, 2016	Combined Three Months Ended	Predecessor Three Months Ended

			September 30, 2016	September 30, 2015
Gross partnership wells drilled:				
Barnett/Marble Falls	—	—	—	—
Eagle Ford	—	2	2	10
Mississippi Lime/Hunton	—	—	—	—
Total	—	2	2	10
Net partnership wells drilled:				
Barnett/Marble Falls	—	—	—	—
Eagle Ford	—	2	2	10
Mississippi Lime/Hunton	—	—	—	—
Total	—	2	2	10

	Successor Period September 1 – September 30, 2016	Predecessor Period January 1 – August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
Gross partnership wells drilled:				
Barnett/Marble Falls	—	—	—	2
Eagle Ford	—	2	2	10
Mississippi Lime/Hunton	—	—	—	2
Total	—	2	2	14
Net partnership wells drilled:				
Barnett/Marble Falls	—	—	—	2
Eagle Ford	—	2	2	10
Mississippi Lime/Hunton	—	—	—	1
Total	—	2	2	13

The $5.0 million and $5.9 million decreases in administration and oversight fee revenues during the combined three and nine months ended September 30, 2016, respectively, compared to the prior year periods were primarily due to decreases in the number of wells spud within the combined three and nine months ended September 30, 2016 compared with the prior year periods.

Well Services

	Successor Period September 1 – September 30, 2016	Predecessor Period July 1 – August 31, 2016	Combined Three Months Ended September 30, 2016	Predecessor Three Months Ended September 30, 2015
(in thousands)				
Well services revenues	$ 1,246	$ 2,604	$ 3,850	$ 5,842
Well services expenses	$ (515)	$ (1,025)	$ (1,540)	$ (2,398)

Successor Period September 1 – September 30, 2016	Predecessor Period January 1 – August 31, 2016	Combined Nine Months Ended	Predecessor Nine Months Ended

			September 30, 2016	September 30, 2015
(in thousands)				
Well services revenues	$ 1,246	$ 11,226	$ 12,472	$ 18,568
Well services expenses	$ (515)	$ (4,677)	$ (5,192)	$ (6,735)

Well service revenue and expenses represent the monthly operating fees we charge and the work our service company performs, including work performed for our Drilling Partnership wells during the drilling and completing phase as well as ongoing maintenance of these wells and other wells for which we serve as operator.

The $2.0 million and $6.1 million decreases in well services revenue during the combined three and nine month periods ended September 30, 2016, respectively, as compared to the respective prior year periods are primarily related to lower fee revenue associated with our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls operating areas, which are utilized by our Drilling Partnership wells, an increase in the number of wells having been shut in and certain Drilling Partnerships liquidated in the current year, both of which result in a reduction of the monthly operating fees we charge the Drilling Partnerships.

The $0.9 million and $1.5 million decreases in well services expenses during the combined three and nine months ended September 30, 2016 as compared to the prior year periods are primarily related to lower labor costs.

Gathering and Processing

	Successor Period September 1 – September 30, 2016	Predecessor Period July 1 – August 31, 2016	Combined Three Months Ended September 30, 2016	Predecessor Three Months Ended September 30, 2015
(in thousands)				
Gas gathering margin	$ (272)	$ (589)	$ (861)	$ (788)

	Successor Period September 1 – September 30, 2016	Predecessor Period January 1 – August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
(in thousands)				
Gas gathering margin	$ (272)	$ (1,964)	$ (2,236)	$ (1,360)

Gathering and processing margin includes gathering fees we charge to our Drilling Partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale. Generally, we charge a gathering fee to our Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

The $0.1 million and $0.9 unfavorable movements in gathering and processing margin during the combined three and nine month periods ended September 30, 2016, respectively, as compared to the respective prior year periods were principally due to lower overall natural gas prices in Appalachia and lower gathering fees, particularly from our Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline.

OTHER REVENUES AND EXPENSES

Successor	Predecessor	Predecessor

(in thousands)	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Combined Three Months Ended September 30, 2016	Three Months Ended September 30, 2015
Other Revenues				
Gain (loss) on mark-to-market derivatives	$ (1,330)	$ 3,228	$ 1,898	$ 131,065
Other, net	192	119	311	20
Other Expenses				
General and administrative	$ 4,931	$ 17,166	$ 22,097	$ 13,978
Depreciation, depletion and amortization	6,021	23,278	29,299	40,463
Asset impairment	—	—	—	672,246
Interest expense	3,810	14,928	18,738	25,192
Gain (loss) on asset sales and disposal	10	14	24	(362)
Gain on extinguishment of debt	—	—	—	—
Reorganization items, net	353	16,614	16,967	—
Other income (loss)	—	(3,033)	(3,033)	—
Income tax expense	—	—	—	—

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	Successor Period from September 1, 2016 through September 30, 2016	Predecessor Period from January 1, 2016 through August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
(in thousands)				
Other Revenues				
Gain (loss) on mark-to-market derivatives	$ (1,330)	$ (23,916)	$ (25,246)	$ 209,706
Other, net	192	317	494	80
Other Expenses				
General and administrative	$ 4,931	$ 58,004	$ 62,935	$ 44,400
Depreciation, depletion and amortization	6,021	82,331	88,352	125,948
Asset impairment	—	—	—	672,246
Interest expense	3,810	74,587	78,397	75,105
Gain (loss) on asset sales and disposal	10	(479)	(469)	(276)
Gain on extinguishment of debt	—	26,498	26,498	—
Reorganization items, net	353	16,614	16,967	—
Other income (loss)	—	(9,189)	(9,189)	—
Income tax provision (benefit)	—	—	—	—

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 decreases in mark-to-market derivative gains during the combined three and nine-month periods ended September 30, 2016 compared to the respective prior year periods is due to increases in commodity future prices relative to our hedged derivative positions.

General and Administrative. The $8.1 million increase in general and administrative expenses for the combined three months ended September 30, 2016 as compared to the prior year period is primarily due to $10.9 million related to the write-down of receivables from certain Drilling Partnerships to their estimated net realizable values, a $1.6 million valuation adjustment of our subsidiary’s deferred tax assets and a $1.2 million increase in non-cash stock compensation primarily due to the issuance of shares under the Titan Energy, LLC Management Incentive Plan, partially offset by a $3.3 million decrease in various non-recurring financial advisors and legal counsel costs due to reclassifying the costs to reorganization items, net, a $1.5 million decrease in salaries, wages and benefits and an $0.8 million decrease in other corporate activities.

The $18.5 million increase in general and administrative expenses for the combined nine months ended September 30, 2016 as compared to the prior year period is primarily due to $10.9 million related to the write-down of receivables from certain Drilling Partnerships to their estimated net realizable values, a $7.0 million increase in salaries, wages and benefits, a $2.3 million increase in non-recurring reorganization items, net, a $1.6 million valuation adjustment of our subsidiary's deferred tax assets and a $1.5 million increase in syndication expenses due to lower program fundraising activities, partially offset by a $3.3 million decrease in non-cash stock compensation and a $1.5 million decrease in other corporate activities.

Depreciation, Depletion and Amortization. The decreases in depreciation, depletion and amortization for the combined three and nine month periods ended September 30, 2016 as compared to the respective prior year periods were primarily due to $14.8 million and $42.1 million decreases in our depletion expense, respectively. The following table presents total depletion expense, depletion as a percent of gas and oil production revenue and depletion expense per Mcfe for our operations for the respective periods (in thousands, except for percentage and per Mcfe data):

	Successor	Predecessor		Predecessor
	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Combined Three Months Ended September 30, 2016	Three Months Ended September 30, 2015
Depletion expense:				
Total	$ 5,817	$ 16,512	$ 22,329	$ 37,079
Depletion expense as a percentage of gas and oil production revenue	32 %	42 %	39 %	41 %
Depletion per Mcfe	$ 0.91	$ 1.24	$ 1.14	$ 1.53

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	Successor Period from September 1, 2016 through September 30, 2016	Predecessor Period from January 1, 2016 through August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
Depletion expense:				
Total	$ 5,817	$ 68,647	$ 74,464	$ 116,559
Depletion expense as a percentage of gas and oil production revenue	32 %	49 %	47 %	40 %
Depletion per Mcfe	$ 0.91	$ 1.24	$ 1.21	$ 1.57

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties. The decreases in depletion expense and depletion expense per Mcfe when compared with the comparable prior year periods were due to impairments of our proved properties recorded in the third and fourth quarters of 2015 as a result of lower forecasted commodity prices, which reduced the depletable cost basis of our proved gas and oil properties in the current year periods. The increase in the depletion expense as a percentage of gas and oil revenues for the combined nine months ended September 30, 2016 when compared with the comparable prior year period was due to the decrease in our gas and oil revenues as a result of lower commodity prices and production volumes in the current year period, partially offset by the decrease in depletion expense described above.

Asset Impairment. The $672.2 million asset impairment for the three and nine months ended September 30, 2015 represents the $740.2 million of asset impairment related to oil and gas properties in the Barnett, Coal-bed Methane, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, reduced by $68.0 million of future hedge gains reclassified from accumulated other comprehensive income.

Interest Expense. The decrease in our interest expense during the combined three months ended September 30, 2016 as compared to the prior year period consisted of a $10.7 million decrease associated with interest expense on our Predecessor’s Notes primarily due to only one month of interest expense in the current year period due to the Chapter 11 Filings, partially offset by a $1.8 million increase associated with lower outstanding borrowings under our First Lien Credit Facility at higher interest rates, a $1.6 million decrease in capitalized interest due to lower capital spending (a $2.3 million decrease in our Predecessor’s capitalized interest for the period from July 1, 2016 through September 30, 2016 as compared to the three months ended September 30, 2015, partially offset by $0.7 million for the Successor period from September 1, 2016 through September 30, 2016) and an $0.8 million increase associated with our Second Lien Credit Facility, which replaced our Predecessor’s Old Second Lien Term Loan pursuant to the Plan, with a higher rate of interest than the Old Second Lien Term Loan.

The increase in our interest expense during the combined nine months ended September 30, 2016 as compared to the prior year period consisted of a $4.8 million decrease in capitalized interest due to lower capital spending (a $5.5 million decrease in our Predecessor's capitalized interest for the period from January 1, 2016 through August 31, 2016 as compared to the nine months ended September 30, 2015, partially offset by $0.7 million for the Successor period from September 1, 2016 through September 30, 2016), a $4.6 million increase associated primarily with two months of interest expense with a higher rate of interest under our Second Lien Credit Facility, which replaced our Predecessor's Old Second Lien Term Loan pursuant to the Plan, a $4.5 million increase associated with higher interest rates on lower outstanding borrowings under our First Lien Credit Facility and a $1.9 million increase primarily associated with amortization of our Predecessor's deferred financing costs, partially offset by a $10.5 million decrease associated with interest expense on our Predecessor's Notes due to only seven months of interest expense in the current year period resulting from the Chapter 11 Filings , a $1.3 million decrease associated with interest expense on our Predecessor's Notes due to our Predecessor's repurchases of Notes in the first quarter of 2016, and a $0.7 million decrease in amortization of our deferred financing costs.

Gain on Early Extinguishment of Debt. The gain on early extinguishment of debt for the combined nine months ended September 30, 2016 represents a $26.5 million gain related to the repurchase of a portion of our Predecessor's 7.75% and 9.25% Senior Notes. Of the $26.5 million gain, $27.4 million related to the gain from the redemption of the principal values and accrued interest, partially offset by $0.9 million related to the accelerated amortization of the related deferred financing costs.

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

Professional fees and other	$	(33,065)

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

Other income (loss). The $3.0 million loss for the combined three months ended September 30, 2016 represents a non-cash loss for the write-off of notes receivables with certain investors of our Drilling Partnerships.

The $9.2 million loss for the combined nine months ended September 30, 2016 represents $6.1 million of non-cash losses, net of liquidation and transfer adjustments, of certain Drilling Partnerships' liquidation and transfer of oil and gas properties and asset retirement obligations to us and $3.0 million of non-cash loss for the write-off of notes receivables with certain investors of our Drilling Partnerships.

Income Tax Provision (Benefit). For the one month ended September 30, 2016, we recorded a full valuation allowance against our deferred tax asset balance which reduced our effective tax rate to zero. 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.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary sources of liquidity are cash generated from operations, capital raised through our Drilling Partnerships, and borrowings under our revolving credit facility (see "Credit Facilities"). Our primary cash requirements, in addition to normal operating expenses, are for debt service including interest and capital expenditures. In general, we expect to fund:

- capital expenditures through existing cash and cash flows from operating activities;
- capital expenditures and working capital deficits through existing cash, cash flows from operations, additional borrowings and capital raised through Drilling Partnerships; and
- debt service principal payments through additional borrowings as they become due or by the issuance of additional common shares or asset sales.

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. 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 have continued to decline and remain low in 2016. 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, challenges with our ability to raise capital through our Drilling Partnerships, either as a result of downturn in commodity prices or other difficulties affecting the fundraising channel, could negatively impact our ability to remain in compliance with the covenants under our credit facilities.

If we are unable to remain in compliance with the covenants under our credit facilities (as described in "Credit Facilities"), absent relief from our lenders, as applicable, we may be forced to repay or refinance such indebtedness. Upon the occurrence of an 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. If an event of default occurs (including if our borrowing base is redetermined below our current outstanding borrowings and we are unable to repay the deficiency or deposit additional collateral to eliminate such deficiency), or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we will not have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there would be substantial doubt regarding our ability to continue as a going concern.

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, meeting our debt service obligations and/or achieving cost efficiency. For example, 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 also continue to implement various cost saving measures to reduce our capital, operating and general and administrative costs, including renegotiating contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs. We will continue to be opportunistic and aggressive in managing our cost structure and, in turn, our liquidity to meet our capital and operating needs. We cannot provide any assurances that any of these efforts will be successful or will result in cost reductions or cash flows or the timing of any such cost reductions or additional cash flows. It is also possible additional adjustments to our plan and outlook may occur based on market conditions and our needs at that time, which could include selling assets, seeking additional partners to develop our assets, and/or reducing our planned capital program. In addition, to the extent commodity prices remain low or decline further, or we experience disruptions in our longer-term access to or cost of capital, our ability to fund future capital expenditures or growth projects may be further impacted.

During 2016, we have taken steps to improve our liquidity, strengthen our balance sheet and expand our financial flexibility including reducing our debt by approximately $900 million and interest expense by $80 million per year. See “Recent Developments – Restructuring and Chapter 11 Bankruptcy Proceedings” and “Restructuring Support Agreement” for further information regarding our Restructuring Support Agreement and the Plan.

Cash Flows – Combined Nine Months Ended September 30, 2016 Compared with the Nine Months Ended September 30, 2016

	Successor Period from September 1, 2016 through September 30, 2016	Predecessor Period from January 1, 2016 through August 31, 2016	Combined Nine Months Ended September 30, 2016	Predecessor Nine Months Ended September 30, 2015
Net cash provided by operating activities	$ 9,398	$ 221,106	$ 230,504	$ 101,308
Net cash used in investing activities	(5,367)	(24,894)	(30,261)	(138,863))
Net cash provided by (used in) financing activities	(150)	(182,137)	(182,287)	24,726

The change in cash flows provided by operating activities when compared with the comparable prior year period was primarily due to:

- an increase from our $243.5 million sale of substantially all of our commodity hedge positions on July 25, 2016 and July 26, 2016 pursuant to our Restructuring Support Agreement;

- an increase in our working capital of $17.4 million primarily due to decreases in accounts payable, accrued liabilities and liabilities associated with drilling contracts as a result of lower operating activities, an increase due to derivative cash settlements; and a decrease in advances to affiliates; partially offset by lower accounts receivable, as a result of revenue declines, lower subscription receivables, due to a decline in fund raising for well drilling activities, and an increase in cash outflow for well drilling liabilities,

- a decrease in cash interest of $33.5 million due to the exchange of our Notes for 90% common equity interest in us, pursuant to the Plan and our senior note repurchases in January and February 2016, partially offset by higher outstanding balances with higher interest rates on our revolving credit facility and a decrease in capitalized interest due to reduced drilling activities in the current year period; and

- a decrease in oil and gas production costs of $33.1 million due to cost control measures and lower production activities; partially offset by

- a decrease in our gas and oil production revenues of $134.7 million, due to lower commodity pricing and production volumes;

- an increase in our reorganization costs of $37.4 million representing incremental costs incurred as a result of our Chapter 11 Filings in our condensed consolidated statement of operations;

- a decrease in our well construction and completion and well services margins totaling $10.2 million, due to lower revenue generating activities, partially offset by lower associated expenses; and

- an increase in general and administrative expenses of $9.3 million due to higher salaries, wages, and benefits, and costs associated with our restructuring and an increase in syndication expenses due to lower program fundraising activities.

The change in cash flows used in investing activities when compared with the comparable prior year period was primarily due to:

- a decrease of $72.0 million in capital expenditures due to lower capital expenditures related to our drilling activities; and
- a decrease of $37.0 million in net cash paid for acquisitions due to adjustments in working capital settlements for our Eagle Ford acquisition in 2015.

The change in cash flows provided by (used in) financing activities when compared with the comparable prior year period was primarily due to:

- a decrease of $242.5 million in net borrowings under our second lien term loan facility due to the second lien term loan proceeds of $242.5 million, net of $7.5 million in discount, issued in the first half of 2015;
- an $89.2 decrease in net proceeds from the issuance of common limited partner units in the first nine months of 2015 under our equity distribution programs;
- an increase of $24.3 million in net repayments on our revolving credit facility;
- a decrease of $6.9 million in net proceeds from the issuance of common limited partner units in the first nine months of 2015 under our equity distribution programs; and
- an increase of $5.5 million related to our senior note repurchases in the first quarter of 2016; partially offset by
  - a decrease of $107.1 million in distributions paid to unitholders primarily due to a reduction in our monthly cash distribution per common limited partner unit from $0.1966 per unit to $0.0125 per unit through the month of February 2016, and suspension of our monthly cash distributions beginning with the month of March of 2016, due to the continued lower commodity price environment;
- an increase of $44.9 million related to the Arkoma transaction adjustment reflected in the first nine months of 2015; and
- a decrease of $9.7 million in deferred financing costs primarily related to the issuance of our $250.0 million second lien term loan in the first nine months of 2015.

Capital Requirements

At September 30, 2016, 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. The following table summarizes our total capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Successor	Predecessor		Successor
	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Combined Three Months Ended September 30, 2016	Three Months Ended September 30, 2015
Total capital expenditures	$ 5,367	$ 6,074	$ 11,441	$ 32,799

	Successor	Predecessor		Predecessor
	Period from September 1, 2016 through September 30, 2016	Period from January 1, 2016 through August 31, 2016	Combined Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Total capital expenditures	$ 5,367	$ 24,894	$ 30,261	$ 102,290

During the three months ended September 30, 2016, our total capital expenditures consisted primarily of $7.1 million for wells drilled exclusively for our own account compared with $14.4 million for the comparable prior year period, $0.2 million of investments in our Drilling Partnerships compared with $7.3 million for the prior year comparable period, $0.8 million of leasehold acquisition

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costs compared with $6.1 million for the prior year comparable period and $3.3 million of corporate and other costs compared with $5.0 million for the prior year comparable period.

During the nine months ended September 30, 2016, our total capital expenditures consisted primarily of $16.9 million for wells drilled exclusively for our own account compared with $40.1 million for the comparable prior year period, $0.8 million of investments in our Drilling Partnerships compared with $26.0 million for the prior year comparable period, $2.8 million of leasehold acquisition costs compared with $9.9 million for the prior year comparable period and $9.8 million of corporate and other costs compared with $26.3 million for the prior year comparable period.

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 September 30, 2016, we are committed to expend approximately $4.3 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 September 30, 2016, our off-balance sheet arrangements were limited to our letters of credit outstanding of $4.2 million and commitments to spend $4.3 million related to our drilling and completion and capital expenditures, excluding acquisitions.

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner’s share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally, for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of September 30, 2016, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

CREDIT FACILITIES

First Lien Credit Facility

On September 1, 2016, we entered into a $440 million third amended and restated first lien credit agreement with Wells Fargo Bank, National Association (“Wells Fargo”), as administrative agent, and the lenders party thereto (the “First Lien Credit Facility”). 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.
- The non-conforming tranche matures on May 1, 2017 and the conforming reserve-based tranche matures on August 23, 2019.
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Borrowing base will be redetermined semi-annually, with additional interim re-determinations permitted under certain circumstances. The first scheduled borrowing base redetermination shall occur on May 1, 2017; provided, that a super majority of the lenders may elect, in certain circumstances, to seek an interim redetermination of the borrowing base prior to May 1, 2017.

- Obligations are secured by mortgages on substantially all of our oil and gas properties and first priority security interests in substantially all of our assets and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.
- Borrowings bear interest at our election at either LIBOR plus an applicable margin between 3.00% and 4.00% per annum or the "alternate base rate" plus an applicable margin between 2.00% and 3.00% per annum, which fluctuates based on utilization. We are also required to pay a fee of 0.50% per annum on the unused portion of the borrowing base. At September 30, 2016, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 5.1%.
- Contains covenants that limits 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 its assets.
- Requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017.

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- Requires us to maintain certain financial ratios (which will first be tested for the period ending December 31, 2016 and will use an annualized EBITDA measurement for periods prior to June 30, 2017):
  - o Total Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 5.00 to 1.00;
  - o Current assets to current liabilities (each as defined in the First Lien Credit Facility) of not less than 1.00 to 1.00;
  - o First Lien Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 3.50 to 1.00; and
  - o EBITDA to Interest Expense (each as defined in the First Lien Credit Facility) of not less than 2.50 to 1.00.

Second Lien Credit Facility

On September 1, 2016, we entered into an amended and restated second lien credit agreement with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto (the "Second Lien Credit Facility") 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:
  - o 4.5% of the principal amount prepaid for prepayments prior to February 23, 2017;
  - o 2.25% of the principal amount prepaid for prepayments on or after February 23, 2017 and prior to February 23, 2018; and
  - o 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 limits 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 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 first be tested for the period ending December 31, 2016 and will use an annualized EBITDA measurement for periods prior to June 30, 2017):
  - o EBITDA to Interest Expense (each as defined in the Second Lien Credit Facility) of not less than 2.50 to 1.00;
  - o 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
  - o current assets to current liabilities (each as defined in the Second Lien Credit Facility) of not less than 1.0 to 1.0.

Old First Lien Credit Facility

Our Predecessor was party to a Second Amended and Restated Credit Agreement, dated as of July 31, 2013 by and among our Predecessor, the lenders from time to time party thereto, and Wells Fargo, as administrative agent, as amended, supplemented or modified from time to time (the "Old First Lien Credit Facility"), which provided for a senior secured revolving credit facility with a maximum borrowing base of $1.5 billion and was scheduled to mature in July 2018.

Pursuant to the Restructuring Support Agreement, we completed the sale of substantially all our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the Old First Lien Credit Facility. As of August 31, 2016 under our Predecessor, the weighted average interest rate on outstanding borrowings under the Old First Lien Credit Facility was 5.5%. Pursuant to the Plan, the Old First

Lien Credit Facility was replaced by the First Lien Credit Facility.

Old Second Lien Term Loan

Our Predecessor was party to a Second Lien Credit Agreement, dated as of February 23, 2015 by and among our Predecessor, the lenders from time to time party thereto, and Wilmington Trust, National Association, as administrative agent, as amended, supplemented or modified from time to time (the “Old Second Lien Term Loan”), which provided for a second lien term loan in an original principal amount of $250.0 million.

As August 31, 2016 under our Predecessor, the weighted average interest rate on outstanding borrowings under the Old Second Lien Term Loan was 10.0%. Pursuant to the Plan, the Old Second Lien Term Loan was replaced by the Second Lien Credit Facility.

Senior Notes

In January and February 2016, we executed transactions to repurchase $20.3 million of our 7.75% Senior Notes and $12.1 million of our 9.25% Senior Notes for $5.5 million, which included $0.6 million of interest. As a result of these transactions, we recognized $26.5 million as gain on early extinguishment of debt, net of accelerated amortization of deferred financing costs of $0.9 million, in our condensed consolidated statement of operations for the Predecessor period from January 1, 2016 through August 31, 2016.

Pursuant to the Plan, Holders of the Notes, in exchange for 100% of the $668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the chapter 11 cases, received 90% of the common equity interests of us.

SECURED HEDGE FACILITY

At September 30, 2016, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as the ultimate general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, 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 its assets.

An event of default occurred under the secured hedging facility agreement upon our filing of voluntary petitions for relief under Chapter 11. The lenders under the secured hedge facility agreed to forbear from exercising remedies in respect of such event of default while the Chapter 11 Filings were pending and, upon occurrence of the effective date of the Plan contemplated by the Restructuring Support Agreement, such event of default is no longer be deemed to exist or to continue under the secured hedge facility.

In addition, it will be an event of default under our First Lien Credit Facility if we, as the ultimate general partner of the Drilling Partnerships, breach an obligation governed by the secured hedge facility, and the effect of such breach is to cause amounts owing under swap agreements governed by the secured hedge facility to become immediately due and payable.

ISSUANCE OF UNITS

As of the Plan Effective Date, we had 5,416,667 shares of our common equity outstanding. Titan Management holds our Series A Preferred Share, which entitles Titan Management to receive to 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. 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.

On September 1, 2016, we adopted the Titan Energy, LLC Management Incentive Plan (the "MIP") for the employees, directors and individual consultants of us and our affiliates. On October 26, 2016, the MIP was amended and restated to increase the number of shares that may be issued. The MIP permits the grant of options, phantom shares and restricted and unrestricted common shares, as well as dividend equivalent rights. Subject to adjustment in accordance with the MIP, a maximum of 655,555 common shares may be issued pursuant to awards under the MIP. Common Shares subject to forfeited awards or withheld to satisfy exercise prices or tax withholding obligations will again be available for delivery pursuant to other awards. The MIP has a term of 10 years and will be administered by the Board of Directors, which may delegate to a committee or the Company's chief executive officer. On September 1, 2016, 138,750 common shares from the MIP were issued and vested immediately as the service inception date was the date of the Chapter 11 Filings and the service completion date was the Plan Effective Date, resulting in \$0.7 million of non-cash compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the Predecessor periods from July 1, 2016 to August 31, 2016 and January 1, 2016 to August 31, 2016. Also on September 1, 2016, 277,917 common shares from the MIP were issued and vest 33% on each of the next three anniversaries of the date of grant, resulting in \$0.1 million of non-cash compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the Successor period from September 1, 2016 to September 30, 2016. At September 30, 2016, we had \$1.5 million in unrecognized compensation expense related to unvested common shares. The fair value of the common shares was determined in connection with our estimate of the equity value of the Successor utilizing the discounted cash flow method (see Notes 3 and 7).

On the Plan Effective Date, all of our Predecessor's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any distribution or consideration.

Our Predecessor had an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to its equity distribution agreement, our Predecessor sold from time to time through the Agents its common units representing limited partner interests of the Predecessor having an aggregate offering price of up to $100.0 million. Sales of its common units were made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the former trading market for its common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. Our Predecessor paid each of the Agents a commission, which in each case was not more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of its equity distribution agreement, our Predecessor sold common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of its common units to an Agent as principal was pursuant to the terms of a separate terms agreement between the Predecessor and such Agent. During the Predecessor period from July 1, 2016 through August 31, 2016, our Predecessor did not issue any common limited partner units under its equity distribution program. During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor issued 245,175 common limited partner units under its equity distribution program for net proceeds of $0.2 million, net of $4,000 in commissions and offering expenses paid. During the Predecessor three months ended September 30, 2015, our Predecessor issued 5,519,110 common limited partner units under its equity distribution program for net proceeds of $18.6 million, net of $0.3 million in commissions and offering expenses paid. During the Predecessor nine months ended September 30, 2015, our Predecessor issued 8,404,934 common limited partner units under its equity distribution program for net proceeds of $40.0 million, net of $1.0 million in commissions and offering expenses paid.

In August 2015, our Predecessor entered into a distribution agreement with MLV & Co. LLC ("MLV"), which it terminated and replaced in November 2015, when our Predecessor entered into a distribution agreement with MLV and FBR Capital Markets & Co. in which it sold its 8.625% Class D Cumulative Redeemable Perpetual Preferred Units ("Class D Preferred Units") and Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units"). Under both the August 2015 ATM Agreement and the November 2015 ATM Agreement, our Predecessor did not issue any Class D Preferred units nor Class E Preferred Units under its preferred equity distribution program for the Predecessor period from January 1, 2016 through August 31, 2016. During the three and nine months ended September 30, 2015, our Predecessor issued 90,328 Class D Preferred Units and 1,083 Class E Preferred Units under its preferred equity distribution program for net proceeds of $1.0 million, net of $0.2 million in commissions and offering expenses paid.

In May 2015, in connection with the Arkoma Acquisition, our Predecessor issued 6,500,000 of its common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of $49.7 million. Our Predecessor used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under its Old First Lien Credit Facility.

In April 2015, our Predecessor issued 255,000 of its Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of $6.0 million.

On March 31, 2015, to partially pay its portion of a quarterly installment related to the Eagle Ford acquisition, our Predecessor issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit.

On July 31, 2016, our Predecessor's 3,749,986 Class C Preferred Units that were issued to ATLS on July 31, 2013, were converted into 3,749,986 common units and the associated warrant issued to ATLS to purchase 562,497 of its common units expired.

On July 12, 2016, our Predecessor received notification from the New York Stock Exchange ("NYSE") that the NYSE commenced proceedings to delist its common units as a result of our failure to comply with the continued listed standards set forth in Section 802.01C of the NYSE Listed Company Manual to maintain an average closing price of $1.00 per unit over a consecutive 30 day period. Our Predecessor's Class D Preferred Units and Class E Preferred Units were also delisted from the NYSE. Our Predecessor's common units, Class D Preferred Units, and Class E Preferred Units began trading on the OTC market on July 13, 2016 with the ticker symbol "ARPJ" for its common units, "ARPJP" for its Class D Preferred Units, and "ARPJN" for its Class E Preferred Units.

On May 12, 2016, due to the income tax ramifications of the potential options our Predecessor was considering, our Predecessor's Board of Directors delayed the vesting date of approximately 110,000 units granted to employees, directors and officers until March 2017. The phantom units were set to vest between May 15, 2016 and August 31, 2016. The delayed vesting schedule did not have a significant impact on the compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the predecessor period from January 1, 2016 through August 31, 2016. As a result of the

Chapter 11 Filings, our Predecessor's 2012 Long-Term Incentive Plan was cancelled. The remaining unrecognized compensation cost of $0.8 million was recognized upon the cancellation and was recorded in general and administrative expenses on the condensed consolidated statement of operations for the predecessor period from July 1, 2016 through August 31, 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Recently Issued Accounting Standards

See Notes 2 and 5 to our condensed consolidated financial statements for additional information related to recently issued accounting standards.

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, 2015.

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.

General

All of our assets and liabilities are denominated in U.S. dollars, and as a result, we do not have exposure to currency exchange risks.

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, cash flows and financial position as if the hypothetical changes in market risk factors occurred on September 30, 2016. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

We are subject to the risk of loss on our derivative instruments that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the quarterly monitoring of our oil, natural gas and NGLs counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords us netting or set off opportunities to mitigate exposure risk; and (v) when appropriate requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our assets related to derivatives as of September 30, 2016 represent financial instruments from ten counterparties; all of which are financial institutions that have an "investment grade” (minimum Standard & Poor’s rating of BBB+ or better) credit rating and are lenders associated with our revolving credit facility. Subject to the terms of our revolving credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the revolving credit facility.

Interest Rate Risk. At September 30, 2016, $435.8 million was outstanding under our revolving credit facility and $254.5 million was outstanding under our term loan facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would change our consolidated interest expense for the twelve-month period ending September 30, 2017 by approximately $6.9 million.

Commodity Price Risk. Our market risk exposure to commodities is due to the fluctuations in the commodity prices and the impact those price movements have on our financial results. To limit our exposure to changing commodity prices, we use financial derivative instruments, including financial swap and option instruments, to hedge portions of our future production. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under these swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Option instruments are contractual agreements that grant the right, but not the obligation, to purchase or sell commodities at a fixed price for the relevant period.

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 consolidated operating income for the twelve-month period ending September 30, 2017 of approximately $7.6 million.

Realized pricing of our natural gas, oil, and NGL production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production has been volatile and unpredictable for many years. To limit our exposure to changing natural gas, oil and NGL prices, we enter into natural gas and oil swap and put option contracts. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter ("OTC") futures contracts with qualified counterparties. OTC contracts are generally financial contracts which are settled with financial payments or receipts and generally do not require delivery of physical hydrocarbons. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. 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.

At September 30, 2016, we had the following commodity derivatives:

Type	Production Period Ending December 31,	Volumes(1)	Average Fixed Price(1)
Natural Gas – Fixed Price Swaps	2016(2)	13,656,600	$ 2.970
	2017	48,127,700	$ 3.116
	2018	47,559,300	$ 2.959
Crude Oil – Fixed Price Swaps	2016(2)	301,900	$ 42.763
	2017	1,057,900	$ 46.150
	2018	893,500	$ 48.938

(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 2016 include the remaining three months of 2016 beginning October 1, 2016.

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 September 30, 2016, 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 1A: RISK FACTORS

There have been no material changes to the Risk Factors disclosed in Part I – Item 1A "–Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2015 except as follows.

The Chapter 11 cases may have a negative impact on our image, which may negatively impact our business going forward.

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Negative events or publicity associated with our Chapter 11 cases could adversely affect our relationships with our suppliers, service providers, customers, employees, and other third parties. In addition, we may face greater difficulties in attracting, motivating and retaining management. These and other related issues could adversely affect our operations and financial condition.

Even following the consummation of the Plan, we may not be able to achieve our stated goals and continue as a going concern.

Even following the consummation of the Plan, we will continue to face a number of risks, including further deterioration in commodity prices or other changes in economic conditions, changes in our industry, changes in demand for our oil and gas and increasing expenses. Accordingly, we cannot guarantee that the Plan or any other plan of reorganization will achieve our stated goals.

Furthermore, even following the reduction in our debts as a result of the consummation of the Plan, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business. Our access to additional financing is, and for the foreseeable future will likely continue to be, extremely limited, if it is available at all.

Our ability to continue as a going concern is dependent upon our ability to raise additional capital. As a result, we cannot give any assurance of our ability to continue as a going concern.

Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time.

We face uncertainty regarding the adequacy of our liquidity and capital resources and have extremely limited, if any, access to additional financing. In addition to the cash requirements necessary to fund our ongoing operations, we incurred significant fees and other costs in connection with the Chapter 11 Filings. We cannot assure you that our cash on hand and cash flow from operations will be sufficient to continue to fund our operations and allow us to satisfy our obligations following the consummation of the Plan.

Our financial results may be volatile and may not reflect historical trends.

Following the consummation of the Plan, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities and expenses, contract terminations and rejections, and claims assessments may significantly impact our consolidated financial performance. As a result, our historical financial performance is likely not indicative of our financial performance following the commencement of the Chapter 11

Filings.

In addition, following the consummation of the Plan, the amounts reported in subsequent consolidated financial statements may materially change relative to historical consolidated financial statements, including as a result of revisions to our operating plans pursuant to a plan of reorganization. We have adopted fresh start accounting, in which case our assets and liabilities will be recorded at fair value as of the fresh start reporting date, which may differ materially from the recorded values of assets and liabilities on our consolidated balance sheets. Our financial results after the application of fresh start accounting also may be different from historical trends.

The Plan was based in large part upon assumptions and analyses developed by us. If these assumptions prove to be incorrect, we may be unsuccessful.

The Plan has affected both our capital structure and the ownership, structure and operation of our businesses and reflects assumptions and analyses based on our experience and perception of historical trends, current conditions and expected future developments, as well as other factors that we consider appropriate under the circumstances. Whether actual future results and developments will be consistent with our expectations and assumptions depends on a number of factors, including but not limited to (i) our ability to obtain adequate liquidity and financing sources; (ii) our ability to maintain customers' confidence in our viability as a continuing entity and to attract and retain sufficient business from them; (iii) our ability to retain key employees, and (iv) the overall strength and stability of general economic conditions of the financial and oil and gas industries, both in the U.S. and in global markets. The failure of any of these factors could materially adversely affect the successful reorganization of our businesses.

In addition, the Plan relied upon financial projections, including with respect to revenues, EBITDA, capital expenditures, debt service and cash flow. Financial forecasts are necessarily speculative, and it is likely that one or more of the assumptions and estimates that are the basis of these financial forecasts will not be accurate. Accordingly, we expect that our actual financial condition and results of operations will differ, perhaps materially, from what we have anticipated. Consequently, there can be no assurance that the results or developments contemplated by the Plan will occur or, even if they do occur, that they will have the anticipated effects on us and our subsidiaries or our businesses or operations.

ITEM 6: EXHIBITS

2.1 Joint Prepackaged Chapter 11 Plan of Reorganization of Atlas Resource Partners, L.P., et al., pursuant to Chapter 11 of the Bankruptcy Code[(1)]

2.2 Confirmation Order, dated August 26, 2016[(1)]

3.1 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 Current Report on Form 8-K filed September 7, 2016) (2)

4.1 Instrument of Resignation, Appointment and Acceptance, dated as of June 6, 2016, by and among Atlas Resource Partners Holdings, LLC, Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the Subsidiary Guarantors named therein, Wells Fargo Bank, National Association and U.S. Bank National Association[(3)]

10.1 Forbearance and Waiver Agreement, dated as of July 11, 2016, by and among Atlas Resources, LLC, Wells Fargo Bank, National Association, as administrative agent, and the other lenders thereto.

10.2 Forbearance Agreement, dated as of July 11, 2016, among Atlas Resource Partners, L.P., Atlas Resource Partners Holdings, LLC, Atlas Resource Finance Corporation, the subsidiary guarantors and the forbearing holders party thereto.

10.3 Restructuring Support Agreement dated July 25, 2016[(4)]

10.4 Third Amended and Restated Credit Agreement, dated as of September 1, 2016, among Titan Energy Operating, LLC, Titan Energy, LLC, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent.[(2)]

10.5 Amended and Restated Second Lien Credit Agreement, dated as of September 1, 2016, among Titan Energy Operating, LLC, Titan Energy, LLC, the lenders from time to time party thereto and Wilmington Trust, National Association, as administrative agent and collateral agent.[(2)]

10.6 Registration Rights Agreement, dated as of September 1, 2016, by and among Titan Energy, LLC and the holders party thereto.[(2)]

10.7 Delegation of Management Agreement, dated as of September 1, 2016, by and between Titan Energy, LLC and Titan Energy Management, LLC.[(2)]

10.8 Omnibus Agreement, dated as of September 1, 2016, by and among Titan Energy, LLC, Titan Energy Operating, LLC, Titan Energy Management, LLC and Atlas Energy Resource Services, Inc.[(2)]

10.9 Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Edward E. Cohen.[(2)]

10.10 Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Jonathan Z. Cohen.[(2)]

10.11 Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Daniel C. Herz.[(2)]

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	Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Mark Schumacher.[2]
10.13	Titan Energy, LLC Management Incentive Plan.[2]
10.14	Amended and Restated Titan Energy, LLC Management Incentive Plan [5]
10.15	Form of Stock Grant Agreement – Initial Award.[2]
31.1	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2	Rule 13(a)-14(a)/15(d)-14(a) Certification

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32.1	Section 1350 Certification
32.2	Section 1350 Certification
101.INS	XBRL Instance Document(6)
101.SCH	XBRL Schema Document(6)
101.CAL	XBRL Calculation Linkbase Document(6)
101.LAB	XBRL Label Linkbase Document(6)
101.PRE	XBRL Presentation Linkbase Document(6)
101.DEF	XBRL Definition Linkbase Document(6)

(1) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 29, 2016.
(2) Previously filed as an exhibit to our Current Report on Form 8-K filed on September 7, 2016.
(3) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 7, 2016.
(4) Previously filed as an exhibit to our Current Report on Form 8-K filed on July 25, 2016.
(5) Previously filed as an exhibit to our Current Report on Form 8-K filed on November 11, 2016.
(6) 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: November 21, 2016	By: /s/ DANIEL C. HERZ Daniel C. Herz Chief Executive Officer
Date: November 21, 2016	By: /s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback Chief Financial Officer
Date: November 21, 2016	By: /s/ MATTHEW J. FINKBEINER Matthew J. Finkbeiner Chief Accounting Officer

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