Vanguard Natural Resources, Inc.
Form 10-Q
November 09, 2018

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

FORM 10-Q

(Mark One)

x	QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2018	
OR	
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to
Commission File Number: 001-33756
Vanguard Natural Resources, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	80-0411494
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

5847 San Felipe, Suite 3000 Houston, Texas	77057
(Address of Principal Executive Offices)	(Zip Code)

(832) 327-2255
(Registrant's Telephone Number, Including Area Code)

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

o Large accelerated filer	o Accelerated filer

o Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company
	o Emerging growth company

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.   Yes   No

As of November 6, 2018, the registrant had 20,124,080 outstanding shares of common stock, $0.001 par value.

VANGUARD NATURAL RESOURCES, INC. AND SUBSIDIARIES

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GLOSSARY OF TERMS

Below is a list of terms that are common to our industry and used throughout this document:

/day	= per day	Mcf	= thousand cubic feet
Bbls	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
Bcf	= billion cubic feet	MMBbls	= million barrels
Bcfe	= billion cubic feet equivalents	MMBOE	= million barrels of oil equivalent
BOE	= barrel of oil equivalent	MMBtu	= million British thermal units
Btu	= British thermal unit	MMcf	= million cubic feet
MBbls	= thousand barrels	MMcfe	= million cubic feet of natural gas equivalents
MBOE	= thousand barrels of oil equivalent	NGLs	= natural gas liquids

When we refer to oil, natural gas and natural gas liquids (“NGLs”) in “equivalents,” we are doing so to compare quantities of natural gas with quantities of NGLs and oil or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which 42 gallons is equal to one Bbl of oil or one Bbl of NGLs and one Bbl of oil or one Bbl of NGLs is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

References in this report to the “Successor” are to Vanguard Natural Resources, Inc., formerly known as VNR Finance Corp., and its subsidiaries, including Vanguard Natural Gas, LLC (“VNG”), VNR Holdings, LLC (“VNRH”), Vanguard Operating, LLC (“VO”), Escambia Operating Co. LLC (“EOC”), Escambia Asset Co. LLC (“EAC”), Eagle Rock Energy Acquisition Co., Inc. (“ERAC”), Eagle Rock Upstream Development Co., Inc. (“ERUD”), Eagle Rock Acquisition Partnership, L.P. (“ERAP”), Eagle Rock Energy Acquisition Co. II, Inc. (“ERAC II”), Eagle Rock Upstream Development Co. II, Inc. (“ERUD II”) and Eagle Rock Acquisition Partnership II, L.P. (“ERAP II”).

References in this report to the “Predecessor” are to Vanguard Natural Resources, LLC, individually and collectively with its subsidiaries.

References in this report to “us,” “we,” “our,” the “Company,” “Vanguard,” or “VNR” or like terms refer to Vanguard Natural Resources, LLC for the period prior to emergence from bankruptcy on August 1, 2017 (the “Effective Date”) and to Vanguard Natural Resources, Inc. for the period as of and following the Effective Date.

Forward-Looking Statements

Certain statements and information in this Quarterly Report on Form 10-Q (the “Quarterly Report”) may constitute “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Statements included in this Quarterly Report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in Management’s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “may,” “believe,” “expect,” “intend,” “anticipate,” “estimate,” “continue,” or other sim words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. Forward-looking statements include, but are not limited to, statements we make concerning future actions, conditions or events, future operating results, income or cash flow.

These statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. Such forward-looking statements are subject to various risks and uncertainties that could cause actual results to differ materially from those anticipated as of the date of this report. Although we believe that the expectations reflected in these forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to be correct. Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things, those set forth in the Risk Factors section of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (the “2017 Annual Report”), and this Quarterly Report, and those set forth from time to time in our filings with the Securities and Exchange Commission (the “SEC”), which are available on our website at www.vnrenergy.com and through the SEC’s Electronic Data Gathering and Retrieval System at www.sec.gov. These factors and risks include, but are not limited to:

- our ability to obtain sufficient financing to execute our business plan post-emergence;
- our ability to meet our liquidity needs;
- our ability to access the public capital markets;
- risks relating to any of our unforeseen liabilities;
- declines in oil, NGLs or natural gas prices;
- the level of success in exploration, development and production activities;
- adverse weather conditions that may negatively impact development or production activities;
- the timing of exploitation and development expenditures;
- inaccuracies of reserve estimates or assumptions underlying them;
- revisions to reserve estimates as a result of changes in commodity prices;

- impacts to financial statements as a result of impairment write-downs;
- risks related to the level of indebtedness and periodic redeterminations of the borrowing base under our credit agreements;
- ability to comply with restrictive covenants contained in the agreements governing our indebtedness that may adversely affect operational flexibility;
- ability to generate sufficient cash flows from operations to meet the internally funded portion of any capital expenditures budget;
- ability to obtain external capital to finance exploration and development operations and acquisitions;

- federal, state and local initiatives and efforts relating to the regulation of development drilling and hydraulic fracturing;
- failure of properties to yield oil or natural gas in commercially viable quantities;
- uninsured or underinsured losses resulting from oil and natural gas operations;
- ability to access oil and natural gas markets due to market conditions or operational impediments;
- the impact and costs of compliance with laws and regulations governing oil and natural gas operations;
- ability to replace oil and natural gas reserves;
- any loss of senior management or technical personnel;
- competition in the oil and natural gas industry;
- risks arising out of hedging transactions;
- the costs and effects of litigation;
- sabotage, terrorism or other malicious intentional acts (including cyber-attacks), war and other similar acts that disrupt operations or cause damage greater than covered by insurance; and
- costs of tax treatment as a corporation.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I – FINANCIAL INFORMATION

Item 1. Unaudited Condensed Consolidated Financial Statements

VANGUARD NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share/unit data)
(Unaudited)

	Successor		Predecessor
	Three Months Ended September 30, 2018	Two Months Ended September 30, 2017	One Month Ended July 31, 2017
Revenues:			
Oil sales	$42,909	$27,303	$11,820
Natural gas sales	46,448	39,032	4,412
NGLs sales	27,073	13,465	4,792
Oil, natural gas and NGLs sales	116,430	79,800	21,024
Net losses on commodity derivative contracts	(30,887)	(32,352)	(12,019)
Total revenues and losses on commodity derivative contracts	85,543	47,448	9,005
Costs and expenses:			
Production:			
Lease operating expenses	35,424	26,447	11,787
Transportation, gathering, processing and compression	9,551	8,044	—
Production and other taxes	9,748	5,737	1,983
Depreciation, depletion, amortization, and accretion	35,568	27,578	7,328
Impairment of oil and natural gas properties	1,965	—	—
Exploration expense	219	105	—
Selling, general and administrative expenses	10,733	7,194	8,738
Total costs and expenses	103,208	75,105	29,836
Loss from operations	(17,665)	(27,657)	(20,831)
Other income (expense):			
Interest expense	(16,060)	(9,615)	(5,003)
Net gains on divestiture of oil and natural gas properties	1,747	—	—
Other	614	36	472
Total other expense, net	(13,699)	(9,579)	(4,531)
Loss before reorganization items	(31,364)	(37,236)	(25,362)
Reorganization items (Note 3)	(732)	—	988,452
Net income (loss)	(32,096)	(37,236)	963,090
Less: Net income attributable to non-controlling interests	(37)	(61)	(1)
Net income (loss) attributable to Vanguard stockholders/unitholders	(32,133)	(37,297)	963,089
Net income (loss) per share/unit – basic and diluted	$(1.60)	$(1.86)	$7.33
Weighted average Common shares/units outstanding			
Common shares/units – basic and diluted	20,100	20,056	130,978
Predecessor Class B units – basic and diluted	—	—	420

See accompanying notes to condensed consolidated financial statements

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VANGUARD NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share/unit data)
(Unaudited)

	Successor		Predecessor
	Nine Months Ended September 30, 2018	Two Months Ended September 30, 2017	Seven Months Ended July 31, 2017
Revenues:			
Oil sales	$135,523	$27,303	$97,496
Natural gas sales	144,338	39,032	113,587
NGLs sales	71,557	13,465	35,565
Oil, natural gas and NGLs sales	351,418	79,800	246,648
Net losses on commodity derivative contracts	(94,804)	(32,352)	(24,887)
Total revenues and losses on commodity derivative contracts	256,614	47,448	221,761
Costs and expenses:			
Production:			
Lease operating expenses	103,182	26,447	87,092
Transportation, gathering, processing and compression	30,821	8,044	—
Production and other taxes	27,500	5,737	21,186
Depreciation, depletion, amortization, and accretion	114,318	27,578	58,384
Impairment of oil and natural gas properties	24,118	—	—
Exploration expense	1,965	105	—
Selling, general and administrative expenses	34,577	7,194	28,810
Total costs and expenses	336,481	75,105	195,472
Income (loss) from operations	(79,867)	(27,657)	26,289
Other income (expense):			
Interest expense	(46,683)	(9,615)	(35,276)
Net gains on interest rate derivative contracts	—	—	30
Net gains on divestiture of oil and natural gas properties	6,647	—	—
Other	588	36	783
Total other expense, net	(39,448)	(9,579)	(34,463)
Loss before reorganization items	(119,315)	(37,236)	(8,174)
Reorganization items (Note 3)	(3,049)	—	908,485
Net income (loss)	(122,364)	(37,236)	900,311
Less: Net income attributable to non-controlling interests	(226)	(61)	(13)
Net income (loss) attributable to Vanguard stockholders/unitholders	(122,590)	(37,297)	900,298
Distributions to Preferred unitholders	—	—	(2,230)
Net income (loss) attributable to Common stockholders/ Common and Class B unitholders	$(122,590)	$(37,297)	$898,068
Net income (loss) per share/unit – basic and diluted	$(6.10)	$(1.86)	$6.84
Weighted average Common shares/units outstanding			
Common shares/units – basic and diluted	20,100	20,056	130,962
Predecessor Class B units – basic and diluted	—	—	420

See accompanying notes to condensed consolidated financial statements

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VANGUARD NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)
(Unaudited)

	Successor September 30, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$3,966	$2,762
Trade accounts receivable, net	52,131	67,248
Derivative assets	87	2,258
Restricted cash	4,450	7,255
Prepaid drilling costs	17,169	11,830
Assets held for sale	11,503	—
Other current assets	6,847	3,934
Total current assets	96,153	95,287
Oil and natural gas properties		
Proved properties	1,548,477	1,560,552
Unproved properties	82,202	85,393
	1,630,679	1,645,945
Accumulated depreciation, depletion, amortization and impairment	(230,829)	(112,553)
Oil and natural gas properties, net – successful efforts method	1,399,850	1,533,392
Other assets		
Derivative assets	1,696	—
Other assets	9,611	14,841
Total assets	$1,507,310	$1,643,520
Liabilities and stockholders’ equity		
Current liabilities		
Accounts payable:		
Trade	$12,048	$9,141
Accrued liabilities:		
Lease operating	11,864	13,560
Developmental capital	8,313	12,275
Interest	3,459	6,312
Production and other taxes	25,721	20,982
Other	11,360	9,005
Derivative liabilities	70,095	39,212
Oil and natural gas revenue payable	32,062	37,422
Liabilities held for sale	1,649	—
Other current liabilities	11,506	12,175
Total current liabilities	188,077	160,084
Long-term debt, net of current portion (Note 6)	863,921	905,976
Derivative liabilities	40,872	27,483
Asset retirement obligations, net of current portion	139,625	151,717
Other long-term liabilities	501	732
Total liabilities	1,232,996	1,245,992
Commitments and contingencies (Note 10)		

Stockholders’ equity (Note 11)		
Successor common stock ($0.001 par value, 50,000,000 shares authorized; 20,101,077 and 20,100,178 shares issued and outstanding at September 30, 2018 and December 31, 2017, respectively)	20	20
Successor additional paid-in capital	508,294	506,640
Successor accumulated deficit	(234,000)	(111,410)
Total stockholders' equity	274,314	395,250
Non-controlling interest in subsidiary	—	2,278
Total stockholders' equity attributable to Common stockholders	274,314	397,528
Total liabilities and stockholders’ equity	$1,507,310	$1,643,520

See accompanying notes to condensed consolidated financial statements

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CONDENSED CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (SUCCESSOR)
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2018
(in thousands)
(Unaudited)

	Common Stock	Amount	Additional Paid-in Capital	Accumulated Deficit	Non-controlling Interest	Total Stockholders' Equity
Balance at December 31, 2017 (Successor)	20,100	$ 20	$ 506,640	$ (111,410)	$ 2,278	$ 397,528
Net income (loss)	—	—	—	(122,590)	226	(122,364)
Share-based compensation	1	—	1,654	—	—	1,654
Potato Hills cash distribution to non-controlling interest	—	—	—	—	(427)	(427)
Disposition of non-controlling interest	—	—	—	—	(2,077)	(2,077)
Balance at September 30, 2018 (Successor)	20,101	$ 20	$ 508,294	$ (234,000)	$ —	$ 274,314

See accompanying notes to condensed consolidated financial statements

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VANGUARD NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

(in thousands)	Successor Nine Months Ended September 30, 2018	Two Months Ended September 30, 2017	Predecessor Seven Months Ended July 31, 2017
Operating activities			
Net income (loss)	$(122,364)	$(37,236)	$900,311
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization, and accretion	114,318	27,578	58,384
Impairment of oil and natural gas properties	24,118	—	—
Amortization of deferred financing costs	2,174	443	2,584
Amortization of debt discount	—	—	348
Non-cash reorganization items	—	—	(937,956)
Compensation related items	1,654	—	5,429
Net losses on commodity and interest rate derivative contracts	94,804	32,352	24,858
Cash settlements received (paid) on matured commodity derivative contracts	(50,057)	(2,326)	7
Cash settlements paid on matured interest rate derivative contracts	—	—	(95)
Net gain on divestiture of oil and natural gas properties	(6,647)	—	—
Changes in operating assets and liabilities:			
Trade accounts receivable	15,533	(398)	34,845
Other current assets	(5,853)	(253)	1,435
Net premiums paid on commodity derivative contracts	—	—	(16)
Increase in restricted cash	—	—	(28,455)
Accounts payable and oil and natural gas revenue payable	(2,477)	(6,692)	19,444
Payable to affiliates	—	—	(895)
Accrued expenses and other current liabilities	(3,015)	(186)	(27,018)
Other assets	804	446	(922)
Net cash provided by operating activities	62,992	13,728	52,288
Investing activities			
Additions to property and equipment	(166)	—	(102)
Additions to oil and natural gas properties	(60,755)	(14,431)	(25,694)
Deposits and prepayments of oil and natural gas properties	(51,014)	(9,013)	(23,731)
Proceeds from the sale of oil and natural gas properties	92,156	—	126,363
Net cash provided by (used in) investing activities	(19,779)	(23,444)	76,836
Financing activities			
Proceeds from long-term debt	118,500	—	—
Repayment of long-term debt	(161,327)	(835)	(41,603)
Proceeds from Term Loan borrowings	—	—	125,000
Repayment of debt under the predecessor revolving credit facility	—	—	(500,266)
Proceeds from rights offerings and second lien investment	—	—	275,000
Potato Hills distribution to non-controlling interest	(427)	(128)	(235)
Financing fees	(1,560)	(166)	(9,367)
Net cash used in financing activities	(44,814)	(1,129)	(151,471)
Net decrease in cash, cash equivalents and restricted cash	(1,601)	(10,845)	(22,347)

Cash, cash equivalents and restricted cash, beginning of period	10,017	27,610	49,957
Cash, cash equivalents and restricted cash, end of period	$8,416	$16,765	$27,610
Supplemental cash flow information:			
Cash paid for interest	$47,241	$4,196	$29,631
Non-cash investing activity:			
Assets held for sale	$11,503	$—	$—
Liabilities held for sale	$1,649	$—	$—
Asset retirement obligations, net	$18,325	$206	$9,581

See accompanying notes to condensed consolidated financial statements

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VANGUARD NATURAL RESOURCES, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Description of the Business

We are an exploration and production company engaged in the production and development of oil and natural gas properties in the United States. The Company is currently focused on adding value by efficiently operating our producing assets and, in certain areas, applying modern drilling and completion technologies in order to fully assess and realize potential development upside. Our primary business objective is to increase shareholder value by growing reserves, production and cash flow in a capital efficient manner. Through our operating subsidiaries, as of September 30, 2018, we own properties and oil and natural gas reserves primarily located in nine operating areas:

- the Green River Basin in Wyoming;
- the Piceance Basin in Colorado;
- the Permian Basin in West Texas and New Mexico;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Gulf Coast Basin in Texas, Louisiana and Alabama;
- the Big Horn Basin in Wyoming and Montana;
- the Anadarko Basin in Oklahoma and North Texas;
- the Wind River Basin in Wyoming; and
- the Powder River Basin in Wyoming.

Following the completion of the financial restructuring on August 1, 2017 (see Note 1, “Summary of Significant Accounting Policies, (b) Emergence from Voluntary Reorganization under Chapter 11 and (c) Fresh-Start Accounting”), the Company had 20.1 million shares of its common stock outstanding. The Company’s shares of common stock and warrants are traded and quoted on the OTCQX market (which is operated by OTC Markets Group, Inc.) under the symbol VNRR.

1. Summary of Significant Accounting Policies

The accompanying condensed consolidated financial statements are unaudited and were prepared from our records. We derived the condensed consolidated balance sheet as of December 31, 2017 from the audited financial statements contained in our 2017 Annual Report. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles in the United States ("GAAP"). You should read this Quarterly Report along with our 2017 Annual Report, which contains a summary of our significant accounting policies and other disclosures. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Information for interim periods may not be indicative of our operating results for the entire year.

As of September 30, 2018, our significant accounting policies are consistent with those discussed in Note 1 of the Notes to the Consolidated Financial Statements contained in our 2017 Annual Report.

(a) Basis of Presentation and Principles of Consolidation

The condensed consolidated financial statements as of September 30, 2018 (Successor) and December 31, 2017 (Successor), and for the three and nine months ended September 30, 2018 (Successor) and for the two months ended September 30, 2017 (Successor), and the one and seven months ended July 31, 2017 (Predecessor), respectively, include our accounts and those of our subsidiaries. All intercompany transactions and balances have been eliminated upon consolidation.

We consolidated the Potato Hills Gas Gathering System as we had the ability to control the operating and financial decisions and policies of the entity through our 51% ownership and reflected the non-controlling interest as a separate element in our condensed consolidated financial statements. On August 1, 2018, we completed the sale of our 51% joint venture interest in Potato Hills Gas Gathering System, including the compression assets relating to the gathering system and our working interest in related oil and natural gas producing properties (the "Potato Hills Divestment"). Please see Note 5, "Divestitures," for further discussion.

(b) Emergence from Voluntary Reorganization under Chapter 11

On February 1, 2017 (the "Petition Date"), the Predecessor and certain of its subsidiaries (such subsidiaries, together with the Predecessor, the "Debtors") filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). During the pendency of the Chapter 11 proceedings, the Debtors operated their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. On July 18, 2017, the Bankruptcy Court entered an order confirming the Final Plan (as defined in Note 2). The Company emerged from bankruptcy effective August 1, 2017. Please read Note 2, "Emergence From Voluntary Reorganization Under Chapter 11 Proceedings" for a discussion of the Chapter 11 Cases and the Final Plan.

In accordance with Accounting Standards Codification ("ASC") 852, Reorganizations ("ASC 852"), the Successor was required to apply fresh-start accounting upon its emergence from bankruptcy. The Successor evaluated transaction activity between July 31, 2017 and the Effective Date and concluded that an accounting convenience date of July 31, 2017 (the "Convenience Date") was appropriate for the adoption of fresh-start accounting which resulted in the Successor becoming a new entity for financial reporting purposes as of the Convenience Date.

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to July 31, 2017. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company prior to, and including, July 31, 2017. As such, these periods are not comparable, are labeled Successor or Predecessor, and are separated by a bold black line.

(c) Cash, Cash Equivalents and Restricted Cash

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the condensed consolidated balance sheets to the amounts shown in the condensed consolidated statements of cash flows (in thousands):

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	Successor	
	September 30, 2018	December 31, 2017
Cash and cash equivalents	$3,966	$ 2,762
Restricted cash	4,450	7,255
Total cash, cash equivalents and restricted cash	$8,416	$ 10,017

(d) Oil and Natural Gas Properties - Transition from Full Cost Method to Successful Efforts Accounting Method

Under GAAP, there are two allowed methods of accounting for oil and natural gas properties: the full cost method and the successful efforts method. Entities engaged in the production of oil and natural gas have the option of selecting either method for application in the accounting for their properties. The principal differences between the two methods are in the treatment of exploration costs, the calculation of depreciation, depletion and amortization expense (“DD&A”), and the assessment of impairment of oil and natural gas properties.

Prior to July 31, 2017, we followed the full cost method of accounting. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil, natural gas and NGLs reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and ceiling test limitations. Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurred on a quarterly basis. Specifically, costs are transferred to the amortizable base when properties are determined to have proved reserves. In addition, we transferred unproved property costs to the amortizable base when unproved properties were evaluated as being impaired and as exploratory wells were determined to be unsuccessful. Additionally, the amortizable base includes estimated future development costs, dismantlement, restoration and abandonment costs net of estimated salvage values. Capitalized costs are limited to a ceiling based on the present value of future net revenues, computed using the 12-month unweighted average of first-day-of-the-month historical price, the “12-month average price” discounted at 10%, plus the lower of cost or fair market value of unproved properties.

Because a new entity was created at the Effective Date, and the Successor’s financial statements are not comparable to the Predecessor’s financial statements (refer to Note 3, “Fresh-Start Accounting”), upon emergence from bankruptcy, we elected to adopt the successful efforts method of accounting for our oil and natural gas properties. We believe that application of successful efforts accounting provides greater transparency in the results of our oil and natural gas properties and enhances decision making and capital allocation processes. Additionally, application of the successful efforts method eliminates proved property impairments based on historical prices, which are not indicative of the fair value of our oil and natural gas properties, and better reflects the true economics of developing our oil and natural gas reserves. Therefore, from August 1, 2017 we have used the successful efforts method to account for our investment in oil and natural gas properties in the Successor.

Under the successful efforts method, we capitalize the costs of acquiring unproved and proved oil and natural gas leasehold acreage. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current exploration and development plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, and the remaining months in the lease term for the property. Development costs are capitalized, including the costs of unsuccessful and successful development wells and the costs to drill and equip exploratory wells that find proved reserves. Exploration costs, including unsuccessful exploratory wells and geological and geophysical costs, are expensed as incurred.

Depreciation, depletion and amortization

DD&A of the leasehold and development costs that are capitalized into proved oil and natural gas properties are computed using the units-of-production method, at the district level, based on total proved reserves and proved developed reserves, respectively. Upon sale or retirement of oil and gas properties, the costs and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Impairment of Oil and Natural Gas Properties

Proved oil and natural gas properties are assessed for impairment in accordance with ASC Topic 360, Property, Plant and Equipment, when events and circumstances indicate a decline in the recoverability of the carrying values of such properties, such as a negative revision of reserves estimates or sustained decrease in commodity prices, but at least annually. We estimate future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. If the sum of the undiscounted pretax cash flows is less than the carrying amount, then the carrying amount is written down to its estimated fair value.

Unproved properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of unproved oil and natural gas properties for impairment and recognizes a loss at the time of impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, future reserve cash flows and the remaining lease term.

(e) Income Taxes

Prior to July 31, 2017, the Predecessor was a limited liability company treated as a partnership for federal and state income tax purposes, in which the taxable income or loss of the Predecessor were passed through to its unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Predecessor's subsidiaries were C corporations subject to federal and state income taxes. Therefore, with the exception of the state of Texas and certain subsidiaries, the Predecessor did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of the Predecessor.

Effective upon consummation of the Final Plan, the Successor became a C corporation subject to federal and state income taxes. As a C corporation, we account for income taxes, as required, under the liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in net income or loss in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company incurred a net taxable loss in the current taxable period. Thus no current income taxes are anticipated to be paid and no net benefit will be recorded in the Company's condensed consolidated financial statements due to the full valuation allowance on the tax assets.

Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At September 30, 2018, we did not have any accrued liability for uncertain tax positions and do not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). In response, the SEC staff issued Staff Accounting Bulletin 118 ("SAB 118"), which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC Topic 740, "Uncertain Tax Positions" ("ASC Topic 740"). In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the Tax Act for which the accounting under ASC Topic 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC Topic 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Tax Act. Refer to Note 13, “Income Taxes,” for more information on the Company’s accounting for income taxes.

(f) New Pronouncements Recently Adopted

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five-step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing GAAP.

Throughout 2015 and 2016, the FASB issued a series of updates to the revenue recognition guidance in ASC Topic 606, including ASU No. 2015-14, Revenue from Contracts with Customers (ASC Topic 606): Deferral of the Effective Date, ASU No. 2016-08, Revenue from Contracts with Customers ("ASC Topic 606"): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients, and ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers.

In conjunction with fresh-start accounting, the Company elected to early adopt the standard effective August 1, 2017. We adopted the standard using the modified retrospective method, by which fresh-start accounting allowed us to apply the new standard to all new contracts entered into on or after August 1, 2017, and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of August 1, 2017. The adoption of this guidance did not have a material impact on the Company's financial statements. See Note 4, "Impact of ASC Topic 606," for further details related to the Company's adoption of this standard.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (ASC Topic 230): Restricted Cash ("ASU 2016-18"), which is intended to address diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. ASU 2016-18 was applied retrospectively as of the date of adoption and is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years (early adoption permitted). The Company adopted ASU 2016-18 effective January 1, 2018. The adoption of this ASU resulted in the inclusion of restricted cash in the beginning and ending balances of cash on the condensed consolidated statements of cash flows and disclosure reconciling cash and cash equivalents presented on the condensed consolidated balance sheets to cash, cash equivalents and restricted cash on the condensed consolidated statements of cash flows. The adoption of this guidance did not have a material impact on the Company's financial position of results of operations as the impact was primarily related to presentation.

(g) New Pronouncements Issued But Not Yet Adopted

In February 2016, the FASB issued ASU No. 2016-02, Leases (ASC Topic 842) ("ASU 2016-02"), which requires lessees to recognize at the commencement date for all leases, with the exception of short-term leases, (i) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis, and (ii) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. ASU 2016-02 will take effect for public companies for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 and should be adopted using a modified retrospective approach. We are currently evaluating the provisions of ASU 2016-02 and assessing the impact, if any, it may have on our financial position and results of operations. As part of our assessment work to date, we have formed an implementation work team, conducted training for the relevant staff regarding the potential impacts of the new ASU and are continuing our contracts analysis and policy review. We have engaged external resources to assist us in our efforts of completing the analysis of potential changes to our current accounting practices. Additionally, we have not determined the effect of the ASU on our internal control over financial reporting or other changes in business practices and processes.

(h) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGLs reserves and related future cash flows, the fair value of derivative contracts, asset retirement obligations, accrued oil, natural gas and NGLs revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion expense, income taxes, and non-cash compensation. Actual results could differ from those estimates.

(i) Prior Year Financial Statement Presentation

Certain prior year balances have been reclassified to conform to the current year presentation of balances as stated in this Quarterly Report.

2. Emergence from Voluntary Reorganization under Chapter 11 of the Bankruptcy Code

On February 1, 2017, the Debtors filed voluntary petitions for relief (collectively, the "Bankruptcy Petitions" and, the cases commenced thereby, the "Chapter 11 Cases") under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Chapter 11 Cases were administered under the caption "In re Vanguard Natural Resources, LLC, et al."

On July 18, 2017, the Bankruptcy Court entered the Order Confirming Debtors' Modified Second Amended Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (the "Confirmation Order"), which approved and confirmed the Debtors' Modified Second Amended Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (the "Final Plan"). The Final Plan provided for the reorganization of the Debtors as a going concern and significantly reduced the long-term debt and annual interest payments of the Successor. During the pendency of the Chapter 11 Cases, we operated our business as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

The Debtors satisfied all conditions precedent under the Final Plan and emerged from bankruptcy on August 1, 2017. The Successor reorganized as a Delaware corporation named Vanguard Natural Resources, Inc. on the Effective Date. Pursuant to the Final Plan, each of the Predecessor's equity securities outstanding immediately before the Effective Date (including any unvested restricted units held by employees or officers of the Debtor, or options and warrants to purchase such securities) have been cancelled and are of no further force or effect as of the Effective Date. Under the Final Plan, the Debtors' new organizational documents became effective on the Effective Date. The Successor's new organizational documents authorize the Successor to issue new equity, certain of which was issued to holders of allowed claims pursuant to the Final Plan on the Effective Date. In addition, on the Effective Date, the Successor entered into a registration rights agreement with certain equity holders. As of August 1, 2017, the Successor issued 20.1 million outstanding shares of common stock, $0.001 par value ("Common Stock").

3. Fresh-Start Accounting

Upon the Company's emergence from chapter 11 bankruptcy, the Company qualified for and applied fresh-start accounting in accordance with the provisions set forth in ASC 852 as (i) the Reorganization Value (as defined below) of the Company's assets immediately prior to the date of confirmation was less than the post-petition liabilities and allowed claims, and (ii) the holders of the existing voting shares of the Predecessor entity received less than 50% of the voting shares of the emerging entity. Refer to Note 2, "Emergence from Voluntary Reorganization under Chapter 11 of the Bankruptcy Code" for the terms of the Final Plan. Fresh-start accounting requires the Company to present its assets, liabilities, and equity as if it were a new entity upon emergence from bankruptcy. The new entity is referred to as "Successor" or "Successor Company." However, the Company will continue to present financial information for any periods before application of fresh-start accounting for the Predecessor Company. The Predecessor and Successor companies lack comparability, as required in ASC Topic 205, Presentation of Financial Statements ("ASC 205"). ASC 205 states financial statements are required to be presented comparably from year to year, with any exceptions to comparability clearly disclosed. Therefore, "black-line" financial statements are presented to distinguish between the Predecessor and Successor companies.

Adopting fresh-start accounting resulted in a new financial reporting entity with no beginning retained earnings or deficit as of the fresh-start reporting date. Upon the application of fresh-start accounting, the Company allocated the fair value of the Successor Company’s total assets (the “Reorganization Value”) to its individual assets based on their estimated fair values. The Reorganization Value was intended to represent the approximate amount a willing buyer would value the Company's assets immediately after the reorganization.

Reorganization Value was derived from an estimate of enterprise value, or the fair value of the Company’s long-term debt and stockholders’ equity (the “Enterprise Value”). The estimated Enterprise Value at the Effective Date was $1.425 billion as established in the Plan and approved by the bankruptcy court. The Enterprise Value was derived from an independent valuation using an asset based methodology of proved reserves, undeveloped acreage, and other financial information, considerations and projections, applying a combination of the income, cost and market approaches as of the Convenience Date.

The Company's principal assets are its oil and natural gas properties. Significant inputs used to determine the fair values of properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.
For purposes of estimating the fair value of the Company's proved, probable and possible reserves, an income approach was used which estimated fair value based on the anticipated cash flows associated with the Company's reserves, risked by reserve category and discounted using a weighted average cost of capital rate of 10.0%. The proved reserve locations were limited to wells expected to be drilled in the Company's five-year development plan. Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $67.20 per barrel of oil, $3.69 per million British thermal units (MMBtu) of natural gas and $24.59 per barrel of oil equivalent of natural gas liquids, after adjustment for transportation fees, quality differentials and regional price differentials. Base pricing was derived from an average of forward strip prices and analysts' estimated prices.

In estimating the fair value of the Company's unproved acreage that was not included in the valuation of probable and possible reserves, a market approach was used in which a review of recent transactions involving properties in the same geographical location indicated the fair value of the Company's unproved acreage from a market participant perspective.

See further discussion below under "Fresh-Start Adjustments" for the specific assumptions used in the valuation of the Company's various other assets.

Although the Company believes the assumptions and estimates used to develop Enterprise Value and Reorganization Value are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating these values are inherently uncertain and require judgment.

The following table reconciles the Company's Enterprise Value to the estimated fair value of the Successor's common stock as of July 31, 2017 (in thousands):

	July 31, 2017
Enterprise Value	$1,425,000
Plus: Cash and cash equivalents	27,610
Less: Debt	(943,393)
Total stockholders' equity	509,217
Less: Fair value of warrants	(11,734)
Less: Fair value of non-controlling interest	(2,274)
Fair Value of Successor common stock	$495,209

The following table reconciles the Company's Debt as of July 31, 2017 (in thousands):

	July 31, 2017
Successor Credit Facility	$730,000
Successor Term Loan	125,000
Senior Notes due 2024	80,722
Lease Financing Obligation, net of current portion	12,464
Current portion of Lease Financing Obligation	4,647
Total Fair value of debt	952,833

Successor Credit Facility fees and debt issuance costs	(9,440)
Total Debt	$943,393

The following table reconciles the Company's Enterprise Value to its Reorganization Value as of July 31, 2017 (in thousands):

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	July 31, 2017
Enterprise Value	$1,425,000
Plus: Cash and cash equivalents	27,610
Plus: Current liabilities, excluding current portion of Lease Financing Obligation	147,552
Plus: Other noncurrent liabilities	15,589
Plus: Long-term asset retirement obligation	136,769
Reorganization Value of Successor assets	$1,752,520

Condensed Consolidated Balance Sheet

The following illustrates the effects on the Company’s unaudited condensed consolidated balance sheet due to the reorganization and fresh-start accounting adjustments. The explanatory notes following the table below provide further details on the adjustments, including the Company’s assumptions and methods used to determine fair value for its assets and liabilities.

	As of July 31, 2017						
(in thousands)	Predecessor	Reorganization Adjustments (1)		Fresh-Start Adjustments		Successor	
Assets							
Current assets							
Cash and cash equivalents	$68,933	$ (41,323	) (2)	$ —		$27,610	
Trade accounts receivable, net	64,253	(155	) (3)	(8,231	) (15)	55,867	
Derivative assets	3,236	—		—		3,236	
Restricted cash	102,556	(74,101	) (4)	—		28,455	
Other current assets	4,430	(394	) (5)	416	(16)	4,452	
Total current assets	243,408	(115,973	)	(7,815	)	119,620	
Oil and natural gas properties, at cost	4,635,867	—		(3,029,173	) (17)	1,606,694	
Accumulated depletion	(3,916,889)	—		3,916,889	(17)	—	
Oil and natural gas properties	718,978	—		887,716		1,606,694	
Other assets							
Goodwill	253,370	—		(253,370	) (18)	—	
Other assets	44,315	—		(18,109	) (19)(20)	26,206	
Total assets	$1,260,071	$ (115,973	)	$ 608,422		$1,752,520	
Liabilities and equity (deficit)							
Current liabilities							
Accounts payable:							
Trade	$8,444	$ 9,978	(6)	$ —		$18,422	
Accrued liabilities:							
Lease operating	13,199	—		—		13,199	
Development capital	8,928	—		—		8,928	
Interest	8,478	(8,478	) (7)	—		—	
Production and other taxes	23,494	—		—		23,494	
Other	20,933	12,297	(8)	—		33,230	
Derivative liabilities	12,987	—		—		12,987	
Oil and natural gas revenue payable	36,087	—		(7,808	) (15)	28,279	
Long-term debt classified as current	1,300,971	(1,300,971	) (9)	—		—	
Other	14,246	(382	) (10)	(203	) (21)	13,661	
Total current liabilities	1,447,767	(1,287,556	)	(8,011	)	152,200	
Long-term debt, net of current portion	12,647	926,281	(11)	(183	) (22)	938,745	
Derivative liabilities	15,143	—		—		15,143	
Asset retirement obligations, net of current portion	260,089	—		(123,320	) (23)	136,769	
Other long-term liabilities	37,683	—		(37,237	) (24)	446	
Total liabilities not subject to compromise	1,773,329	(361,275	)	(168,751	)	1,243,303	
Liabilities subject to compromise	479,911	(479,911	) (12)	—		—	
Total Liabilities	2,253,240	(841,186	)	(168,751	)	1,243,303	

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	As of July 31, 2017			
	Predecessor	Reorganization Adjustments (1)	Fresh-Start Adjustments	Successor
Stockholders' equity/Members' (deficit)				
Preferred units (Predecessor)	335,444	(335,444) (13)	—	—
Common units (Predecessor)	(1,342,849)	763,217 (13)	579,632 (25)	—
Class B units (Predecessor)	7,615	(7,615) (13)	—	—
Common stock (Successor)	—	20 (14)	—	20
Additional paid-in capital (Successor)	—	305,035 (14)	201,888 (25)	506,923
Total VNR stockholders' equity/ members' (deficit)	(999,790)	725,213	781,520	506,943
Non-controlling interest in subsidiary	6,621	—	(4,347) (26)	2,274
Total stockholders' equity/members' (deficit)	(993,169)	725,213	777,173	509,217
Total liabilities and equity (deficit)	$1,260,071	$ (115,973)	$ 608,422	$1,752,520

Reorganization Adjustments:

1) Represents amounts recorded as of the Convenience Date for the implementation of the Final Plan, including, among other items, settlement of the Predecessor's liabilities subject to compromise, repayment of certain of the Predecessor's debt, cancellation of the Predecessor's equity, issuances of the Successor's common stock and equity warrants, proceeds received from the Successor's rights offering and issuance of the Successor's debt.

2) Changes in cash and cash equivalents included the following (in thousands):

Proceeds from equity investment from holders of Old Second Lien Notes	$19,250
Proceeds from rights offering	255,750
Borrowings under the Successor's Term Loan	125,000
Removal of restriction on cash balance	102,556
Payment of holders of claims under the Predecessor Credit Facility	(500,266)
Payment of interest and fees under the Predecessor Credit Facility	(3,390)
Payment of Successor Credit Facility fees	(9,300)
Payment of professional fees	(2,468)
Funding of the general unsecured claims cash distribution pools	(6,750)
Funding of the professional fees escrow account	(21,705)
Changes in cash and cash equivalents	$(41,323)

3) Reflects the write-off of lease incentive costs due to the rejection of the related lease contract.

4) Net change to restricted cash includes the following:

Removal of restriction on cash balance	$(102,556)
Funding of the general unsecured claims cash distribution pools	6,750
Funding of the professional fees escrow account	21,705
	$(74,101)

5) Primarily reflects the write-off of the Predecessor's equity offering costs.

6) Reflects reinstatement of payables for the general unsecured claims and trade claims cash distribution pool.

7) Reflects payment of accrued interest related to Predecessor Credit Facility and Predecessor debtor-in-possession credit facility of $3.4 million and the capitalization of approximately $5.1 million accrued interest on the Old Second Lien Notes into the principal amount of the Senior Notes due 2024.

8) Net increase in other accrued expenses reflect (in thousands):

Recognition of payables for the professional fees escrow account	$12,627
Write-off of accrued non cash compensation related to Phantom Units granted	(330)
Net increase in accounts payable and accrued expenses	$12,297

9) Reflects the repayment of outstanding borrowings under the Predecessor Credit Facility of approximately $500.3 million and the conversion of the remaining outstanding debt to Successor Credit Facility and the Senior Notes due 2024 to Long-Term Debt, net of the write-off of deferred financing fees.

10) Reflects the write-off of deferred rent due to the rejection of the related lease contract.

11) Reflects $855.0 million of outstanding borrowings under the Successor Credit Facility, which includes a $730.0 million revolving loan and a $125.0 million Term Loan. The adjustment also reflects the issuance of Senior Notes due 2024 of $80.7 million. The amounts are presented net of capitalized deferred financing fees related to each debt.

12) Settlement of Liabilities subject to compromise and the resulting net gain were determined as follows (in thousands):

Accounts payable and accrued expenses	$36,224
Accrued interest payable	10,737
Debt	432,950
Total liabilities subject to compromise	479,911
Reinstatement of liability for the general unsecured claims	(4,978)
Reinstatement of liability for settlement of an unsecured claim	(5,000)
Issuance of common shares to holders of general unsecured claims	(1,089)
Issuance of common shares to holders of Senior Notes claims	(16,715)
Gain on settlement of liabilities subject to compromise	$452,129

13) Net change in Predecessor common units reflects (in thousands):

Recognition of gain on settlement of liabilities subject to compromise	$452,129
Cancellation of Predecessor Preferred units	335,444
Cancellation of Predecessor Class B units	7,615
Write-off of deferred financing costs and debt discounts	(4,917)
Recognition of professional and success fees	(14,968)
Fair value of warrants issued to Predecessor unitholders	(11,734)
Fair value of shares issued to Predecessor unitholders	(517)
Terminated contracts	165
Net change in Predecessor Common units	$763,217

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14) Net change in Successor equity reflects net increase in capital accounts as follows (in thousands):

Issuance of common stock to general unsecured creditors	$1,089
Issuance of common stock to holders of Senior Notes claims	16,715
Issuance of common stock to Predecessor preferred unitholders	517
Issuance of common stock for the second lien equity investment	19,250
Issuance of common stock pursuant to the rights offering	255,750
Issuance of warrants	11,734
Change in additional paid-in capital	305,055
Par value of common stock	(20)
Net increase in capital accounts	$305,035

See Note 11, "Stockholders' Equity (Members' Deficit)" for additional information on the issuances of the Successor's equity.

Fresh-Start Adjustments:

15) Reflects a change in accounting policy from the entitlements method for natural gas production imbalances in accordance with the adoption of ASC 606.

16) Reflects fair value adjustment for oil inventory.

17) Reflects the adjustments to oil and natural gas properties, based on the methodology discussed above, and the elimination of accumulated depletion. The following table summarizes the components of oil and natural gas properties as of the Convenience Date (in thousands):

	Successor Fair Value	Predecessor Historical Book Value
Proved properties	$1,511,083	$4,635,867
Unproved properties	95,611	—
	1,606,694	4,635,867
Less: accumulated depletion and amortization	—	(3,916,889)
	$1,606,694	$718,978

18) Reflects the write-off of Predecessor goodwill.

19) Reflects a decrease of other property and equipment and the elimination of accumulated depreciation. The following table summarizes the components of other property and equipment as of the Convenience Date (in thousands):

	Successor Fair Value	Predecessor Historical Book Value
Gas gathering assets	$ 4,196	$ 19,942
Office equipment and furniture	574	5,847
Buildings and leasehold improvements	57	836
Vehicles	1,311	1,549
	6,138	28,174
Less: accumulated depreciation	—	(13,657)
	$ 6,138	$ 14,517

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In estimating the fair value of other property and equipment, the Company used a combination of cost and market approaches. A cost approach was used to value the Company’s other operating assets, based on current replacement costs of the assets less depreciation based on the estimated economic useful lives of the assets and age of the assets. A market approach was used to value the Company’s vehicles, using recent transactions of similar assets to determine the fair value from a market participant perspective.

20) Reflects an adjustment for the intangible asset related to the Company’s nickel gas contract of $5.6 million and the write-off of deferred tax asset of $4.1 million.

21) Reflects the adjustment of current portion of financing obligation to fair value and write-off of deferred rent.

22) Reflects the adjustment of long-term portion of financing obligation to fair value.

23) Primarily reflects the fair value adjustment of asset retirement obligations (“ARO”) to fair value of approximately $145.2 million, of which $136.8 million is reflected as long-term ARO and $8.4 million of current ARO shown in other current liabilities. The fair value of asset retirement obligations was estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate. Refer to Note 9, “Asset Retirement Obligations” for further details of the Company's asset retirement obligations.

24) Reflects the write-off of deferred tax liabilities.

25) Reflects the cumulative impact of the fresh-start accounting adjustments discussed above and the elimination of common units (Predecessor).

26) Reflects the fair value adjustment to the Potato Hills gas gathering assets on the non-controlling interest.

Reorganization Items

Reorganization items represent (i) expenses or income incurred subsequent to the Petition Date as a direct result of the Final Plan, (ii) gains or losses from liabilities settled, and (iii) fresh-start accounting adjustments and are recorded in “Reorganization items” in the Company’s unaudited condensed consolidated statements of operations. The following table summarizes the net reorganization items (in thousands):

	Predecessor Seven Months Ended July 31, 2017
Gain on settlement of Liabilities subject to compromise	$ 452,129
Fresh-start accounting adjustments	781,520
Issuance of common shares and warrants	(214,140)
Legal and other professional fees	(58,482)
Recognition of additional unsecured claims	(31,346)
Write-off of deferred financing costs and debt discounts	(21,361)
Terminated contracts	165
Reorganization items	$ 908,485

Reorganization costs incurred subsequent to the Emergence Date of $0.9 million are recorded in the selling, general and administrative expenses line item in the Company's unaudited consolidated statements of operations for the two months ended September 30, 2017. During the three and nine months ended September 30, 2018, we recorded reorganization costs of$0.7 million and $3.0 million, respectively.

4. Impact of ASC Topic 606 Adoption

In conjunction with the application of fresh-start accounting, we adopted ASC Topic 606, Revenue from Contracts with Customers ("ASC Topic 606"). We adopted using the modified retrospective method, which fresh-start accounting allows us to apply the new standard to all new contracts entered into after August 1, 2017 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of July 31, 2017. ASC Topic 606 supersedes previous revenue recognition requirements in ASC Topic 605, Revenue Recognition ("ASC Topic 605") and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services.

The impact of adoption on our results of operations for the periods indicated is as follows (in thousands):

	Successor		
	Nine Months Ended September 30, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
Revenues:			
Oil sales	$135,523	$135,523	$ —
Natural gas sales	144,338	121,871	22,467
NGLs sales	71,557	63,203	8,354
Oil, natural gas and NGLs sales	351,418	320,597	30,821
Net losses on commodity derivative contracts	(94,804)	(94,804)	—
Total revenues and losses on commodity derivative contracts	$256,614	$225,793	$ 30,821
Costs and expenses:			
Transportation, gathering, processing, and compression	$30,821	$—	$ 30,821
Net loss	$(122,364)	$(122,364)	$ —

	Successor		
	Two Months Ended September 30, 2017		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
Revenues:			
Oil sales	$27,303	$27,303	$ —
Natural gas sales	39,032	32,983	6,049
NGLs sales	13,465	11,470	1,995
Oil, natural gas and NGLs sales	79,800	71,756	8,044
Net losses on commodity derivative contracts	(32,352)	(32,352)	—
Total revenues	$47,448	$39,404	$ 8,044
Costs and expenses:			
Transportation, gathering, processing, and compression	$8,044	$—	$ 8,044
Net loss	$(37,236)	$(37,236)	$ —

Changes to sales of natural gas and NGLs, and transportation, gathering, processing, and compression expense are due to the conclusion that the Company represents the principal and the ultimate third party is our customer in certain natural gas processing and marketing agreements with certain midstream entities in accordance with the control model in ASC Topic 606. This is a change from previous conclusions reached for these agreements utilizing the principal versus agent indicators under ASC Topic 605 where we acted as the agent and the mid-stream processing entity was our customer. As a result, we modified our presentation of revenues and expenses for these agreements. Revenues related to these agreements are now presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Transportation, gathering, processing and compression expenses related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are now presented as Transportation, gathering, processing, and compression expense.

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Revenue from Contracts with Customers

Sales of oil, natural gas and NGLs are recognized at the point control of the product is transferred to the customer and collectability is reasonably assured. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies.

Natural gas and NGLs Sales

Under most of our natural gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds to us for the resulting sales of NGLs and residue gas. In these scenarios, the Company evaluates whether we are the principal or the agent in the transaction. For those contracts where we have concluded we are the principal and the ultimate third party is our customer, we recognize revenue on a gross basis, with transportation, gathering, processing and compression fees presented as an expense in our condensed consolidated statement of operations. Alternatively, for those contracts where we have concluded the Company is the agent and the midstream processing entity is our customer, we recognize natural gas and NGLs revenues based on the net amount of the proceeds received from the midstream processing.

In certain natural gas processing agreements, we may elect to take our residue gas and/or NGLs in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, we deliver product to the ultimate third-party purchaser at a contractually agreed-upon delivery point and receive a specified index price from the purchaser. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as Transportation, gathering, processing and compression expense in our condensed consolidated statements of operations.

Oil sales

Our oil sales contracts are generally structured in one of the following ways:

- We sell oil production at the wellhead and collect an agreed-upon index price, net of pricing differentials. In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead at the net price received.

- We deliver oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title, and risk of loss of the product. Under this arrangement, we pay a third party to transport the product and receive a specified index price from the purchaser with no deduction. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of these third-party transportation fees in our condensed consolidated statements of operations.

Production imbalances

Previously, the Company elected to utilize the entitlements method to account for natural gas production imbalances which is no longer applicable. In conjunction with the adoption of ASC Topic 606, for the three and nine months ended September 30, 2018, there was no material impact to the financial statements due to this change in accounting for our production imbalances.

Transaction price allocated to remaining performance obligations

A significant number of our product sales are short-term in nature with a contract term of one year or less. For those contracts, we have utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For our product sales that have a contract term greater than one year, we have utilized the practical expedient in ASC 606-10-50-14(a) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under our product sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities under ASC Topic 606.

Prior-period performance obligations

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain natural gas and NGL sales may not be received for 30 to 90 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. For the three and nine months ended September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

5. Divestitures and Exchange of Properties

During 2018, the Company completed the sale of certain oil and natural gas properties in the Permian Basin, the Green River Basin and in Mississippi. The Company also sold its working interests in related oil and natural gas producing properties located in multiple counties in Texas, Louisiana and Colorado. Additionally, as discussed in Note 2, the Company completed the Potato Hills Divestment on August 1, 2018. Net cash proceeds received from the sale of all of these properties were approximately $92.2 million, subject to customary post-closing adjustments. Additionally, we incurred costs to sell of approximately $2.4 million. These dispositions were treated as asset sales, and resulted in a net gain of approximately $6.6 million, which is included in “net gains on divestiture of oil and natural gas properties” on the condensed consolidated statement of operations. The net cash proceeds from these divestments were used to pay down outstanding debt under the Successor Credit Facility (defined in Note 6).

In May 2018, the Company completed the trade of its interests in certain properties in the Green River Basin in exchange for interests in other properties within the same basin. The non-cash exchange was accounted for at fair value and no gain or loss was recognized from the exchange.

On September 10, 2018, the Company entered into a purchase and sale agreement for the sale of its ownership in natural gas properties in the Arkoma basin of Arkansas, which comprise all of its interests located in the state (the "Arkansas Divestment"). The Arkansas Divestment closed on October 15, 2018 for a contract price of $12.0 million. The assets and liabilities associated with the Arkansas Divestment are recorded at cost and classified as "held for sale" on the condensed consolidated balance sheet. At September 30, 2018, the Company's condensed consolidated balance sheet included current assets of approximately $11.5 million in "assets held for sale" and current liabilities of approximately $1.6 million in "liabilities held for sale" related to this transaction.

The following table presents carrying amounts of the assets and liabilities of the Company's properties classified as held for sale on the condensed consolidated balance sheet (in thousands):

	Successor September 30, 2018
Assets:	
Oil and natural gas properties, net	$ 11,503
Total assets held for sale	$ 11,503
Liabilities:	
Asset retirement obligations	$ 1,649
Total liabilities held for sale	$ 1,649

6. Debt

Our financing arrangements consisted of the following as of the date indicated (in thousands):

Description	Interest Rate	Maturity Date	Successor September 30, 2018	December 31, 2017
Successor Credit Facility	Variable (1)	February 1, 2021	$662,000	$ 700,000
Successor Term Loan	Variable (2)	May 1, 2021	123,750	124,688
Senior Notes due 2024	9.0%	February 15, 2024	80,722	80,722
Lease Financing Obligations	4.16%	August 10, 2020 (3)	11,666	15,205
Unamortized deferred financing costs			(8,024)	(8,639)
Total debt			$870,114	$ 911,976
Less:				
Current portion of Term Loan			(1,250)	(1,250)
Current portion of Lease Financing Obligation			(4,943)	(4,750)
Total long-term debt			$863,921	$ 905,976

(1) Variable interest rate of 5.90% and 4.90% at September 30, 2018 and December 31, 2017 respectively.
(2) Variable interest rate of 9.65% and 8.90% at September 30, 2018 and December 31, 2017 respectively.
(3) The Lease Financing Obligations expire on August 10, 2020, except for certain obligations which expire on July 10, 2021.

Successor Credit Facility

On the Effective Date, VNG, as borrower, entered into the Fourth Amended and Restated Credit Agreement dated as of August 1, 2017 (the “Successor Credit Facility”), by and among VNG as borrower, Citibank, N.A., as administrative agent (the
“Administrative Agent”) and Issuing Bank, and the lenders party thereto. Pursuant to the Successor Credit Facility, the lenders party thereto agreed to provide VNG with an $850.0 million exit senior secured reserve-based revolving credit facility (the “Revolving Loan”). The initial borrowing base available under the Successor Credit Facility as of the Effective Date was $850.0 million and the aggregate principal amount of Revolving Loans outstanding under the Successor Credit Facility as of the Effective Date was $730.0 million. The Successor Credit Facility also includes an additional $125.0 million senior secured term loan (the “Term Loan”). On December 21, 2017, the borrowing base was reduced to $825.0 million following the completion of the sale of our properties in the Williston Basin and was further reduced to $765.2 million following the completion of the sale of certain of our oil and natural gas properties during the first half of 2018. Please see Note 5 for further discussion on our divestitures.

In July 2018, the Company entered into the Second Amendment to the Successor Credit Facility (the “Second Amendment”) among the Company, the Administrative Agent and the lenders party thereto. Among other things, the Second Amendment reduced the borrowing base from $765.2 million to $729.7 million. The completion of additional divestitures in the third quarter of 2018 also resulted in the reduction of our borrowing base to $700.3 million as of September 30, 2018. Please see Note 5 for further discussion on our divestitures.

During the nine months ended September 30, 2018, we borrowed $118.5 million under the Successor Credit Facility and made repayments under the Successor Credit Facility and Term Loan of $157.4 million. As discussed in Note 5, “Divestitures,” the $92.2 million of net cash proceeds received from the sale of properties were used to pay down debt. We used borrowings under the Successor Credit Facility to partially pay for capital expenditures incurred in the first nine months of 2018 and advances to operators for activities to be completed for the remainder of 2018.

At September 30, 2018, there were $662.0 million of outstanding borrowings and $38.1 million of borrowing capacity under the Successor Credit Facility, after reflecting a $0.2 million reduction in availability for letters of credit (discussed below).

The borrowing base under the Successor Credit Facility is subject to adjustments from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the lenders’ petroleum engineers utilizing the lenders’ internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and NGLs reserves. The next borrowing base redetermination is scheduled for November of 2018.

The maturity date of the Successor Credit Facility is February 1, 2021 with respect to the Revolving Loans and May 1, 2021 with respect to the Term Loan. Until the maturity date for the Term Loan, the Term Loan shall bear an interest rate equal to (i) the alternative base rate plus an applicable margin of 6.50% for an Alternate Base Rate loan or (ii) adjusted 30-day LIBOR plus an applicable margin of 7.50% for a Eurodollar loan. Until the maturity date for the Revolving Loans, the Revolving Loans shall bear interest at a rate per annum equal to (i) the alternative base rate plus an applicable margin of 1.75% to 2.75%, based on the borrowing base utilization percentage under the Successor Credit Facility or (ii) adjusted 30-day LIBOR plus an applicable margin of 2.75% to 3.75%, based on the borrowing base utilization percentage under the Successor Credit Facility.

Unused commitments under the Successor Credit Facility will accrue a commitment fee of 0.5%, payable quarterly in arrears.

VNG may elect, at its option, to prepay any borrowing outstanding under the Revolving Loans without premium or penalty (except with respect to any break funding payments which may be payable pursuant to the terms of the Successor Credit Facility). VNG may be required to make mandatory prepayments of the Revolving Loans in connection with certain borrowing base deficiencies or asset divestitures.

VNG is required to repay the Term Loans on the last day of each March, June, September and December (commencing with the first full fiscal quarter ended after the Effective Date), in each case, in an amount equal to 0.25% of the original principal amount of such Term Loans and, on the Maturity Date, the remainder of the principal amount of the Term Loans outstanding on such date, together in each case with accrued and unpaid interest on the principal amount to be paid but excluding the date of such payment. The table below shows the amounts of required payments under the Term Loan for each year as of September 30, 2018 (in thousands):

Year	Required Payments
2018	$ 312
2019	$ 1,250
2020	$ 1,250
2021 through Maturity date	$ 120,938

Additionally, if (i) VNG has outstanding borrowings, undrawn letters of credit and reimbursement obligations in respect of letters of credit in excess of the aggregate revolving commitments or (ii) unrestricted cash and cash equivalents of VNG and the Guarantors (as defined below) exceeds $35.0 million as of the close of business on the most recently ended business day, VNG is also required to make mandatory prepayments, subject to limited exceptions.

The obligations under the Successor Credit Facility are guaranteed by the Successor and all of VNG’s subsidiaries (the “Guarantors”), subject to limited exceptions, and secured on a first-priority basis by substantially all of VNG’s and the Guarantors’ assets, including, without limitation, liens on at least 95% of the total value of VNG’s and the Guarantors’ oil and natural gas properties, and pledges of stock of all other direct and indirect subsidiaries of VNG, subject to certain limited exceptions.

The Successor Credit Facility contains certain customary representations and warranties, including, without limitation: organization; powers; authority; enforceability; approvals; no conflicts; financial condition; no material adverse change; litigation; environmental matters; compliance with laws and agreements; no defaults; Investment Company Act; taxes; ERISA; disclosure; no material misstatements; insurance; restrictions on liens; locations of businesses and offices; properties and titles; maintenance of properties; gas imbalances; prepayments; marketing of production; swap agreements; use of proceeds; solvency; anti-corruption laws and sanctions; and security instruments.

The Successor Credit Facility also contains certain affirmative and negative covenants, including, without limitation: delivery of financial statements; notices of material events; existence and conduct of business; payment of obligations; performance of obligations under the Successor Credit Facility and the other loan documents; operation and maintenance of properties; maintenance of insurance; maintenance of books and records; compliance with laws and regulations; compliance with environmental laws and regulations; delivery of reserve reports; delivery of title information; requirement to grant additional collateral; compliance with ERISA; requirement to maintain commodity swaps; maintenance of accounts; restrictions on indebtedness; liens; dividends and distributions; repayment of permitted unsecured debt; amendments to certain agreements; investments; change in the nature of business; leases (including oil and gas property leases); sale or discount of receivables; mergers; sale of properties; termination of swap agreements; transactions with affiliates; negative pledges; dividend restrictions; marketing activities; gas imbalances; take-or-pay or other prepayments; swap agreements and transactions and passive holding company status.

The Successor Credit Facility also contains certain financial covenants, as amended under the Second Amendment, including the maintenance of (i) the ratio of consolidated first lien debt of VNG and the Guarantors as of the date of determination to EBITDA for the most recently ended four consecutive fiscal quarter period for which financial statements are available of (a) 5.25:1.00 as of the last day of the fiscal quarter ending September 30, 2018; (b) 5.50:1.00 as of the last day of the fiscal quarter ending December 31, 2018; (c) 5.75:1.00 as of the last day of the fiscal quarter ending March 31, 2019; (d) 5.25:1.00 as of the last day of the fiscal quarter ending June 30, 2019; (e) 5.00:1.00 as of the last day of the fiscal quarter ending September 30, 2019; (f) 4.75:1.00 as of the last day of the fiscal quarters ending December 31, 2019 and March 31, 2020; (g) 4.50:1.00 as of the last day of the fiscal quarter ending June 30, 2020; (h) 4.25:1.00 as of the last day of the fiscal quarter ending September 30, 2020; and (i) 4.00:1.00 as of the last day of the fiscal quarter ending December 31, 2020 and thereafter; (ii) an asset coverage ratio calculated as PV-9 of proved reserves, including impact of hedges and strip prices to first lien debt, of not less than 1.25 to 1.00 as tested on each January 1 and July 1 for the period from August 1, 2017 until August 1, 2018; and (iii) a ratio, determined as of the last day of each fiscal quarter for the four fiscal-quarter period then ending, commencing with the fiscal quarter ending December 31, 2017, of current assets, including any unborrowed capacity on the Successor Credit Facility we are able to draw upon, to current liabilities of VNR and its subsidiaries on a consolidated basis of not less than 1.00 to 1.00.

At September 30, 2018, we were in compliance with all of our debt covenants. Given, in part, the current environment for commodity prices and basis differentials, we updated our internal projections to take such updates into account, and, as a result of these updated projections, we now expect that we may not be in compliance with our ratio of consolidated first lien debt to EBITDA covenant as defined within the Second Amendment to the Successor Credit Facility in certain future periods, beginning with the December 2018 reporting period. In light of these updates, we have taken a number of steps to mitigate a potential default, including (i) discussions with certain banks in our Successor Credit Facility to amend our ratio of consolidated first lien debt to EBITDA covenant, (ii) continue to pursue efforts to divest certain oil and natural gas properties to use proceeds to reduce first lien leverage and (iii) investigating refinancing alternatives. To the extent we breach the consolidated first lien debt to EBITDA covenant as defined within the Second Amendment to the Successor Credit Facility, we would be in default and the lenders would be able to accelerate the maturity of that indebtedness (which could result in an acceleration of our Senior Notes due 2024) and exercise other rights and remedies, all of which could adversely affect our operations and our ability to satisfy our obligations as they come due. These conditions raise substantial doubt about our ability to continue as a going concern within one year after the date that these financial statements are issued. While no assurances can be made that we will be able to consummate such mitigation plans, we believe the combination of the long-term global outlook for commodity prices and our mitigation efforts will be viewed positively by our lenders.

The calculation of EBITDA, as defined under the Second Amendment, among other things, include addbacks in respect of certain exploration expenses, as well as third party fees, costs and expenses in connection with the Plan of Reorganization, also defined in the Second Amendment, together with related severance costs, subject to certain limitations.

The Successor Credit Facility also contains certain events of default, including, without limitation: non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

Senior Notes due 2024

On August 1, 2017, the Company issued approximately $80.7 million aggregate principal amount of new 9.0% Senior Secured Second Lien Notes due 2024 (the “Senior Notes due 2024”) to certain eligible holders of the Predecessor’s second lien notes (the “Existing Notes”) in satisfaction of their claim of approximately $80.7 million related to the Existing Notes held by such holders. The Senior Notes due 2024 were issued in accordance with the exemption from the registration requirements of the Securities Act afforded by Section 4(a)(2) of the Securities Act.

The obligations under the Senior Notes due 2024 are guaranteed by all of the Company’s subsidiaries (“Second Lien Guarantors”) subject to limited exceptions, and secured on a second-priority basis by substantially all of the Company’s and the Second Lien Guarantors’ assets, including, without limitation, liens on the total value of the Company’s and the Second Lien Guarantors’ oil and gas properties, and pledges of stock of all other direct and indirect subsidiaries of the Company, subject to certain limited exceptions.

The Senior Notes due 2024 are governed by an Amended and Restated Indenture, dated as of August 1, 2017 (as amended, the “Amended and Restated Indenture”), by and among the Company, certain subsidiary guarantors of the Company (the “Guarantors”) and Delaware Trust Company, as Trustee (in such capacity, the “Trustee”) and as Collateral Trustee (in such capacity, the “Collateral Trustee”), which contains affirmative and negative covenants that, among other things, limit the ability of the Company and the Guarantors to (i) incur, assume or guarantee additional indebtedness or issue preferred stock; (ii) create liens to secure indebtedness; (iii) make distributions on, purchase or redeem the Company’s Common Stock or purchase or redeem subordinated indebtedness; (iv) make investments; (v) restrict dividends, loans or other asset transfers from the Company’s restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of its properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; (viii) enter into transactions with affiliates; or (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. If the Senior Notes due 2024 achieve an investment grade rating from each of Standard & Poor’s Ratings Services and Moody’s Investors Service, Inc., no default or event of default under the Amended and Restated Indenture exists, and the Company delivers to the Trustee an officers’ certificate certifying such events, many of the foregoing covenants will terminate.

The Amended and Restated Indenture also contains customary events of default, including (i) default for thirty (30) days in the payment when due of interest on the Senior Notes due 2024; (ii) default in payment when due of principal of or premium, if any, on the Senior Notes due 2024 at maturity, upon redemption or otherwise; and (iii) certain events of bankruptcy or insolvency with respect to the Company or any restricted subsidiary of the Company that is a significant subsidiary or any group of restricted subsidiaries of the Company that taken together would constitute a significant subsidiary. If an event of default occurs and is continuing, the Trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Senior Notes due 2024 may declare all the Senior Notes due 2024 to be due and payable immediately. If an event of default arises from certain events of bankruptcy or insolvency, with respect to the Company, any restricted subsidiary of the Company that is a significant subsidiary or any group of restricted subsidiaries of the Company that, taken together, would constitute a significant subsidiary, all outstanding Senior Notes due 2024 will become due and payable immediately without further action or notice.

Interest is payable on the Senior Notes due 2024 on February 15 and August 15 of each year, which began on February 15, 2018. The Senior Notes due 2024 will mature on February 15, 2024.

At any time prior to February 15, 2020, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the Senior Notes due 2024 issued under the Amended and Restated Indenture, with an amount of cash not greater than the net cash proceeds of certain equity offerings, at a redemption price equal to 109% of the principal amount of the Senior Notes due 2024, together with accrued and unpaid interest, if any, to the redemption date; provided that (i) at least 65% of the aggregate principal amount of the Senior Notes due 2024 originally issued under the Amended and Restated Indenture remain outstanding after such redemption, and (ii) the redemption occurs within one hundred eighty (180) days of the equity offering.

On or after February 15, 2020, the Senior Notes due 2024 will be redeemable, in whole or in part, at redemption prices equal to the principal amount multiplied by the percentage set forth below, plus accrued and unpaid interest, if any, to the redemption date, if redeemed during the twelve-month period beginning on February 15 of the years indicated below:

Year	Percentage
2020	106.75 %
2021	104.50 %
2022	102.25 %
2023 and thereafter	100.00 %

In addition, at any time prior to February 15, 2020, the Company may on any one or more occasions redeem all or a part of the Senior Notes due 2024 at a redemption price equal to 100% of the principal amount thereof, plus the Applicable Premium (as defined in the Amended and Restated Indenture) as of, and accrued and unpaid interest, if any, to the date of redemption.

Letters of Credit

At September 30, 2018, we had unused irrevocable standby letters of credit of approximately $0.2 million. The letters are being maintained as security related to the issuance of oil and natural gas well permits to recover potential costs of repairs, modification, or construction to remedy damages to properties caused by the operator. Borrowing availability for the letters of credit was provided under our Successor Credit Facility.

Lease Financing Obligations

On October 24, 2014, as part of our acquisition of certain natural gas, oil and NGLs assets in the Piceance Basin, we entered into an assignment and assumption agreement with Banc of America Leasing & Capital, LLC as the lead bank, whereby we acquired compressors and related facilities and assumed the related financing obligations (the "Lease Financing Obligations"). The Lease Financing Obligations were confirmed during the bankruptcy process. Certain rights, title, interest and obligations under the Lease Financing Obligations have been assigned to several lenders and are covered by separate assignment agreements, which expire on August 10, 2020 and July 10, 2021. We have the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligations also contain an early buyout option whereby the Company may purchase the equipment for

$16.0 million on February 10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 4.16%.

7. Price Risk Management Activities

We have entered into derivative contracts primarily with counterparties that are also lenders under our Successor Credit Facility to hedge price risk associated with a portion of our oil, natural gas and NGLs production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in over hedged volumes. Pricing for these derivative contracts is based on certain market indexes and prices at our primary sales points.

The following tables summarize oil, natural gas, and NGLs commodity derivative contracts in place at September 30, 2018:

Fixed-Price Swaps (NYMEX)

	Gas		Oil		NGLs	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	Weighted Average WTI Price	Gallons	Weighted Average Fixed Price
October 1, 2018 - December 31, 2018	16,928,000	$ 2.89	654,700	$ 46.60	14,296,800	$ 0.60
January 1, 2019 - December 31, 2019	52,539,000	$ 2.79	1,858,200	$ 48.50	32,616,842	$ 0.88
January 1, 2020 - December 31, 2020	47,227,500	$ 2.75	1,393,800	$ 49.53	—	$ —

Basis Swaps

	Gas		
Contract Period	MMBtu	Weighted Avg. Basis Differential ($/MMBtu)	Pricing Index
October 1, 2018 - December 31, 2018	6,915,000	$ (0.57)	Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential
January 1, 2019 - December 31, 2019	5,400,000	$ (0.53)	Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential

	Oil		
Contract Period	Bbls	Weighted Avg. Basis Differential ($/Bbl)	Pricing Index
January 1, 2019 - December 31, 2019	456,250	$ (5.78)	WTI Midland and WTI Cushing Basis Differential

Collars

	Gas			Oil		
Contract Period	MMBtu	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)	Bbls	Floor Price ($/Bbl)	Ceiling Price ($/Bbl)
January 1, 2019 - December 31, 2019	4,125,000	$ 2.60	$ 3.00	575,730	$ 43.81	$ 54.04
January 1, 2020 - December 31, 2020	5,490,000	$ 2.60	$ 3.00	659,340	$ 44.17	$ 55.00
January 1, 2021 - December 31, 2021	1,825,000	$ 2.60	$ 3.07	112,036	$ 47.50	$ 56.05

Balance Sheet Presentation

Our commodity derivatives are presented on a net basis in “derivative assets” and “derivative liabilities” on the condensed consolidated balance sheets as governed by the International Swaps and Derivatives Association Master Agreement with each of the counterparties. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our condensed consolidated balance sheets for the periods indicated (in thousands):

Offsetting Derivative Assets:	Successor September 30, 2018 Gross Amounts of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts Presented in the Condensed Consolidated Balance Sheets
Commodity price derivative contracts	$11,178	$ (9,395)	$ 1,783
Total derivative instruments	$11,178	$ (9,395)	$ 1,783

Offsetting Derivative Liabilities:	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts Presented in the Condensed Consolidated Balance Sheets
Commodity price derivative contracts	$(120,362)	$ 9,395	$ (110,967)
Total derivative instruments	$(120,362)	$ 9,395	$ (110,967)

Offsetting Derivative Assets:	Successor December 31, 2017 Gross Amounts of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts Presented in the Condensed Consolidated Balance Sheets
Commodity price derivative contracts	$15,264	$ (13,006)	$ 2,258
Total derivative instruments	$15,264	$ (13,006)	$ 2,258

Offsetting Derivative Liabilities:	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts Presented in the Condensed Consolidated Balance Sheets
Commodity price derivative contracts	$(79,701)	$ 13,006	$ (66,695)
Total derivative instruments	$(79,701)	$ 13,006	$ (66,695)

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. All of our counterparties were participants in our Successor Credit Facility (see Note 6, “Debt” for further discussion), which is secured by our oil and natural gas properties; therefore, we were not required to post any collateral. The maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $11.2 million at September 30, 2018. We minimize the credit risk related to derivative instruments by: (i) entering into derivative instruments with counterparties that are also lenders in our Successor Credit Facility, and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis.

Changes in fair value of our commodity derivatives for the periods indicated are as follows (in thousands):

	Successor		Predecessor
	Nine Months Ended September 30, 2018	Five Months Ended December 31, 2017	Seven Months Ended July 31, 2017
Derivative liability at beginning of period, net	$(64,437)	$(24,894)	$(125)
Purchases			
Net losses on commodity and interest rate derivative contracts	(94,804)	(55,857)	(24,857)
Settlements			
Cash settlements paid (received) on matured commodity derivative contracts	50,057	12,174	(7)
Cash settlements paid on matured interest rate derivative contracts	—	—	95
Termination of derivative contracts	—	4,140	—
Derivative liability at end of period, net	$(109,184)	$(64,437)	$(24,894)

8. Fair Value Measurements

We estimate the fair values of financial and non-financial assets and liabilities under ASC Topic 820 “Fair Value Measurements and Disclosures” (“ASC Topic 820”). ASC Topic 820 provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based compensation, are not included in the scope of ASC Topic 820. Primarily, ASC Topic 820 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, recognition of asset retirement obligations and to long-lived assets written down to fair value when they are impaired. ASC Topic 820 applies to assets and liabilities carried at fair value on the condensed consolidated balance sheets, as well as to supplemental information about the fair values of financial instruments not carried at fair value.

We have applied the provisions of ASC Topic 820 to assets and liabilities measured at fair value on a recurring basis, which includes our commodity and interest rate derivatives contracts, and on a nonrecurring basis, which includes acquisitions of oil and natural gas properties and other intangible assets and the initial measurement of asset retirement obligations. ASC Topic 820 provides a definition of fair value and a framework for measuring fair value, as well as expanding disclosures regarding fair value measurements. The framework requires fair value measurement techniques to include all significant assumptions that would be made by willing participants in a market transaction.

ASC Topic 820 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC Topic 820 provides a hierarchy of fair value measurements, based on the inputs to the fair value estimation process. It requires disclosure of fair values classified according to the “levels” described below. The hierarchy is based on the reliability of the inputs used in estimating fair value and requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The framework for fair value measurement assumes that transparent “observable” (Level 1) inputs generally provide the most reliable evidence of fair value and should be used to measure fair value whenever available. The classification of a fair value measurement is determined based on the lowest level (with Level 3 as the lowest) of significant input to the fair value estimation process.

The standard describes three levels of inputs that may be used to measure fair value:

Level 1	Quoted prices for identical instruments in active markets.
Level 2	Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.

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Level 3	Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable. Level 3 assets and liabilities generally include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation or for which there is a lack of transparency as to the inputs used.

As required by ASC Topic 820, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

As of the Effective Date, the Company adopted fresh-start accounting, which resulted in the Company becoming a new entity for financial reporting purposes. Upon the adoption of fresh-start accounting, the Company's assets and liabilities were recorded at their fair values as of the Convenience Date of July 31, 2017. See Note 3, “Fresh-start Accounting,” for a detailed discussion of the fair value approaches used by the Company.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Financing arrangements. The carrying amounts of our bank borrowings outstanding, including the term loans, represent their approximate fair value because our current borrowing rates are variable and do not materially differ from market rates for similar bank borrowings. We consider this fair value estimate as a Level 2 input. As of September 30, 2018, the carrying value of our Senior Notes due 2024 approximates its fair value. We consider the inputs to the valuation of our Senior Notes due 2024 to be Level 2.

Derivative instruments. Our commodity derivative instruments consist of fixed-price swaps, basis swap contracts, and collars. We account for our commodity derivatives at fair value on a recurring basis. We estimate the fair values of the fixed-price swaps and basis swap contracts based on published forward commodity price curves for the underlying commodities as of the date of the estimate. We estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates.

Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Management validates the data provided by third parties by understanding the pricing models used, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to our commodity derivatives and interest rate derivatives.

Financial assets and financial liabilities measured at fair value on a recurring basis are summarized below (in thousands):

	Successor	
	September 30, 2018	
	Fair Value Measurements Using Level 2	Assets/Liabilities at Fair Value
Assets:		
Commodity price derivative contracts	$ 1,783	$ 1,783
Total derivative instruments	$ 1,783	$ 1,783

Liabilities:		
Commodity price derivative contracts	$ (110,967)	$ (110,967)
Total derivative instruments	$ (110,967)	$ (110,967)

	Successor December 31, 2017 Fair Value Measurements Using Level 2	Assets/Liabilities at Fair Value
Assets:		
Commodity price derivative contracts	$ 2,258	$ 2,258
Total derivative instruments	$ 2,258	$ 2,258
Liabilities:		
Commodity price derivative contracts	$ (66,695)	$ (66,695)
Total derivative instruments	$ (66,695)	$ (66,695)

During periods of market disruption, including periods of volatile oil and natural gas prices, there may be certain asset classes that were in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, some derivative instruments may fall to Level 3 and thus require more subjectivity and management judgment. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our condensed consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition.

Our nonfinancial assets and liabilities that are initially measured at fair value are comprised primarily of assets acquired in business combinations and asset retirement costs and obligations. These assets and liabilities are recorded at fair value when acquired/incurred but not re-measured at fair value in subsequent periods. We classify such initial measurements as Level 3 since certain significant unobservable inputs are utilized in their determination. A reconciliation of the beginning and ending balance of our asset retirement obligations is presented in Note 9, “Asset Retirement Obligations,” in accordance with ASC Topic 410-20 “Asset Retirement Obligations.” The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Inputs to the valuation include: (i) estimated plug and abandonment cost per well based on our experience; (ii) estimated remaining life per well based on average reserve life per field; (iii) our credit-adjusted risk-free interest rate; and (iv) the average inflation factor. These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are the most sensitive and subject to change.

The Company periodically reviews oil and natural gas properties for impairment when facts and circumstances indicate that their carrying value may not be recoverable. During the nine months ended September 30, 2018 (Successor), we incurred impairment charges of $24.1 million as oil and natural gas properties with a net cost basis of $102.6 million were written down to their fair value of $78.5 million. The write downs primarily relate to downward revisions of unproved property leasehold acreage and working interest in certain of our undeveloped leasehold and a reduction in the value of certain of our operating districts due to a decline in forward natural gas prices. In order to determine whether the carrying value of an asset is recoverable, the Company compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management’s expectations of future oil and natural gas prices. These future price scenarios reflect the Company’s estimation of future price volatility. If the net capitalized cost exceeds the undiscounted future net cash flows, the Company writes the net cost basis down to the discounted future net cash flows, which is management's estimate of fair value. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The inputs used by management for the fair value measurements utilized in this review include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

9. Asset Retirement Obligations

Upon the Company's emergence from bankruptcy on August 1, 2017, as discussed in Note 3, the Company applied fresh-start accounting. This included adjusting the Asset Retirement Obligations based on the estimated fair values at the Convenience Date.

The following provides a roll-forward of our asset retirement obligations (in thousands):

Asset retirement obligation as of January 1, 2017 (Predecessor)	$272,436
Liabilities added during the current period	555
Accretion expense	6,795
Retirements	(1,161)
Liabilities related to assets divested	(10,107)
Change in estimate	(29)
Asset retirement obligation at July 31, 2017 (Predecessor)	268,489
Fresh-start adjustment [1]	(123,320)
Asset retirement obligation at July 31, 2017 (Successor)	145,169
Liabilities added during the current period	10,540
Accretion expense	3,975
Liabilities related to assets divested	(5,066)
Retirements	(812)
Change in estimate	3,618
Asset retirement obligation at December 31, 2017 (Successor)	157,424
Liabilities added during the current period	475
Accretion expense	7,087
Liabilities related to assets divested	(14,880)
Liabilities related to assets held for sale	(1,649)
Retirements	(1,673)
Change in estimate	(2,271)
Asset retirement obligation at September 30, 2018 (Successor)	144,513
Less: current obligations	(4,888)
Long-term asset retirement obligation at September 30, 2018 (Successor)	$139,625

[1]As a result of the application of fresh-start accounting, the Successor recorded its asset retirement obligations at fair value as of the Effective Date. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factor of 1.8%; and (iv) a credit-adjusted risk-free interest rate of 6.4%.

Inputs to the valuation of additions to the asset retirement obligation liability and certain changes in the estimated fair value of the liability include: (i) estimated plug and abandonment cost per well based on our experience; (ii) estimated remaining life per well based on average reserve life per field; (iii) our credit-adjusted risk-free interest rate and (iv) the average inflation factor. These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are sensitive and subject to change. During the five month period ended December 31, 2017 (Successor), we used credit-adjusted risk-free interest rate ranging between 6.2% and 6.4%; and the average inflation factor of 1.8%. During the nine months ended September 30, 2018, our credit-adjusted risk-free interest rate was 6.8% and the average inflation factor was 1.7%.

10. Commitments and Contingencies

Transportation Demand Charges

As of September 30, 2018, we have contracts that provide firm transportation capacity on pipeline systems. The remaining term on these contracts is approximately two years and require us to pay transportation demand charges regardless of the amount of pipeline capacity we utilize.

The values in the table below represent gross future minimum transportation demand charges we are obligated to pay as of September 30, 2018. However, our financial statements will reflect our proportionate share of the charges based on our working interest and net revenue interest, which will vary from property to property.

	September 30, 2018 (in thousands)
October 1, 2018 - December 31, 2018	$ 205
2019	821
2020	410
Total	$ 1,436

Lease Commitments

Rent expense for our office leases was $1.7 million for the nine months ended September 30, 2018 (Successor) and $0.2 million and $1.1 million for the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. The rent expense relates to the lease of our office space in Houston, Texas as well as office leases in our other operating areas. As of September 30, 2018, the minimum contractual obligations were approximately $9.6 million in the aggregate.

	September 30, 2018 (in thousands)
October 1, 2018 - December 31, 2018	$ 334
2019	1,211
2020	1,149
2021	1,170
2022	1,205
Thereafter	4,503
Total	$ 9,572

Development Commitments

We have commitments to third-party operators under joint operating agreements relating to the drilling and completion of oil and natural gas wells. As of September 30, 2018, total estimated costs to be spent in 2018 and 2019 are approximately $12.9 million and $26.6 million, respectively.

Legal Proceedings

Litigation Relating to Vanguard's 2015 merger with LRR Energy, L.P.

In June and July 2015, purported unitholders of LRR Energy, L.P. ("LRE") filed four lawsuits challenging Vanguard's 2015 merger with LRE (the "LRE Merger"). These lawsuits were styled (a) Barry Miller v. LRR Energy, L.P. et al., Case No. 11087-VCG, in the Court of Chancery of the State of Delaware; (b) Christopher Tiberio v. Eric Mullins et al., Cause No. 2015-39864, in the District Court of Harris County, Texas, 334th Judicial District; (c) Eddie Hammond v. Eric Mullins et al., Cause No. 2015-40154, in the District Court of Harris County, Texas, 295th Judicial District; and (d) Ronald Krieger v. LRR Energy, L.P. et al., Civil Action No. 4:15-cv-2017, in the United States District Court for the Southern District of Texas, Houston Division. These lawsuits have been voluntarily dismissed or nonsuited.

On August 18, 2015, another purported LRE unitholder (the "LRE Plaintiff") filed a putative class action lawsuit in connection with the LRE Merger. This lawsuit is styled Robert Hurwitz v. Eric Mullins et al., Civil Action No. 1:15-cv-00711-MAK, in the United States District Court for the District of Delaware (the "LRE Lawsuit"). On June 22, 2016, the LRE Plaintiff filed his Amended Class Action Complaint (the “Amended LRE Complaint”) against LRE, the members of the board of directors of the general partner of LRE, Vanguard, Lighthouse Merger Sub, LLC, and the members of Vanguard’s board of directors (the “LRE Lawsuit Defendants”).

In the Amended LRE Complaint, the LRE Plaintiff alleges multiple causes of action under the Securities Act and Exchange Act related to the registration statement and proxy statement filed with the SEC in connection with the LRE Merger (the “LRE Proxy”). In general, the LRE Plaintiff alleges that the LRE Proxy failed, among other things, to disclose allegedly material details concerning Vanguard’s (x) debt obligations and (y) ability to maintain distributions to unitholders. Based on these allegations, the LRE Plaintiff sought, among other relief, to rescind the LRE Merger, and an award of damages, attorneys' fees, and costs.

On January 2, 2018, the court in the LRE Lawsuit certified a class of plaintiffs that includes all persons or entities holding LRE common units as of August 28, 2015, through the close of the LRE Merger on October 5, 2015, but excluding the LRE Lawsuit Defendants and certain related persons and entities (the "LRE Class"). The window for potential members of the LRE Class to request exclusion from the LRE Class closed on May 29, 2018, with 22 LRE unitholders timely requesting exclusion.

On June 27, 2018, the LRE Lawsuit Defendants and the LRE Plaintiff, on his own behalf and on behalf of the LRE Class, entered into a stipulation of settlement (the "Stipulation"). As amended on July 11, 2018, and on July 25, 2018, the Stipulation provides that the LRE Class will settle and release all claims against the LRE Lawsuit Defendants relating to the LRE Merger, in exchange for an aggregate settlement payment of $8.0 million. Of that settlement amount, Vanguard will contribute $0.7 million, with the remainder to be paid by the insurers of the LRE Lawsuit Defendants. The LRE Lawsuit Defendants continue to deny all allegations of liability or wrongdoing.

On July 18, 2018, the court held a hearing to consider whether to preliminarily approve the proposed settlement. In response to matters raised at that hearing, on July 25, 2018, the LRE Lawsuit Defendants and the LRE Plaintiff amended the Stipulation and submitted to the court a revised notice of proposed settlement, proof of claim and release form, and summary notice of proposed settlement. On July 26, 2018, the court entered an order preliminarily approving the settlement as set forth in the amended Stipulation.

The court has scheduled a hearing to consider final approval of the settlement on December 14, 2018. At that hearing, the court will determine, among other things, whether the proposed settlement is fair and reasonable to the LRE Class and should be approved, thereby forever barring the LRE Class (other than potential members excluded therefrom) from asserting any of the released claims against the LRE Lawsuit Defendants.

We are also defendants in certain legal proceedings arising in the normal course of our business. Management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company's condensed consolidated financial position, results of operations or cash flow, although the ultimate outcome and impact of such legal proceedings on the Company cannot be predicted with certainty. Furthermore, our insurance may not be adequate to cover all liabilities that may arise out of claims brought against us. If one or more negative outcomes were to occur relative to these matters, the aggregate impact to our financial position, results of operations or cash flow could be material.

In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under applicable environmental laws, that could have a material adverse effect on the Company's condensed consolidated financial position, results of operations or cash flow.

11. Stockholders' Equity

Cancellation of Units and Issuance of Common Stock

As previously discussed, all outstanding preferred units issued and outstanding immediately prior to the Effective Date were cancelled and the holders thereof received their pro rata shares of (i) 3% (subject to dilution) of outstanding shares of Common Stock and (ii) Preferred Unit Warrants, in full and final satisfaction of their interests. Further, all common equity of the Predecessor issued and outstanding immediately prior to the Effective Date were cancelled and the holders of the common equity received Common Unit Warrants, in full and final satisfaction of their interests. Please see further discussion below regarding the issuance of new warrants. On the Effective Date, the Company issued 20.1 million shares of Common Stock, $0.001 par value, in accordance with the Final Plan.

Warrant Agreement

On the Effective Date, the Company entered into a warrant agreement (the "Warrant Agreement") with American Stock Transfer & Trust Company, LLC, as warrant agent, pursuant to which the Company issued: (i) to electing holders of the Predecessor's (A) 7.875% Series A Cumulative Redeemable Perpetual Preferred Units ("Series A Preferred Units"), (B) 7.625% Series B Cumulative Redeemable Perpetual Preferred Units ("Series B Preferred Units"), and (C) 7.75% Series C Cumulative Redeemable Perpetual Preferred Units ("Series C Preferred Units" and, together with the Series A Preferred Units and Series B Preferred Units, the "Preferred Units"), three and a half year warrants (the "Preferred Unit Warrants"), which will be exercisable to purchase up to 621,649 shares of Common Stock as of the Effective Date; and (ii) to electing holders of the Predecessor's common units representing limited liability company interests, three and a half year warrants (the "Common Unit Warrants" and, together with the Preferred Unit Warrants, the "Warrants") which will be exercisable to purchase up to 640,876 shares of Common Stock as of the Effective Date. The expiration date of the Warrants is February 1, 2021. The strike price for the Preferred Unit New Warrants is $44.25, and the strike price for the Common Unit New Warrants is $61.45.

Management Incentive Plan

On August 22, 2017, the Company's board of directors (the "Board") approved, upon the recommendation of the Company's Compensation Committee ("Committee"), the Vanguard Natural Resources, Inc. 2017 Management Incentive Plan (the "MIP"), which will assist the Company in attracting, motivating and retaining key personnel and will align the interests of participants with those of stockholders.

The maximum number of shares of common shares available for issuance under the MIP is 2,233,333 shares.

The MIP is administered by the Committee or, in certain instances, its designee. Employees, directors, and consultants of the Company and its subsidiaries are eligible to receive awards of stock options, restricted stock, restricted stock units ("RSUs") or other stock-based awards at the Committee or its designee's discretion.

The Board may amend, modify, suspend, or terminate the MIP in its discretion; however, no amendment, modification, suspension or termination may materially and adversely affect any award previously granted without the consent of the participant or the permitted transferee of the award. No grant will be made under the 2017 Plan more than 10 years after its effective date.

Earnings Per Share/Unit

Basic earnings per share/unit is computed by dividing net earnings attributable to stockholders/unitholders by the weighted average number of shares/units outstanding during the period. Diluted earnings per share/unit is computed by adjusting the average number of shares/units outstanding for the dilutive effect, if any, of potential common shares/units. The Company uses the treasury stock method to determine the dilutive effect.

The diluted earnings per share calculation for each of the three and nine months ended September 30, 2018 excluded approximately 1.3 million warrants and 269,760 RSUs that were antidilutive as we were in a loss position. The diluted earnings per share calculation excludes approximately 1.3 million warrants that were antidilutive for the two months ended September 30, 2017. For the one month and seven months ended July 31, 2017, 13.5 million phantom units were excluded from the calculation of diluted earnings per unit as they were antidilutive

12. Share-Based Compensation

Effect of Emergence from Bankruptcy on Unit-Based Compensation

Pursuant to the Final Plan, all unvested equity grants under the Predecessor's Long-Term Incentive Plan (the "Predecessor Incentive Plan") that were outstanding immediately before the Effective Date were canceled and of no further force or effect as of the Effective Date. In addition, on the Effective Date, the Predecessor's Incentive Plan was canceled and extinguished, and participants in the Predecessor's Incentive Plan received no payment or other distribution on account of the Incentive Plan.

Management Incentive Plan

As discussed in Note 11, "Stockholders' Equity," on August 22, 2017, the Company's Board approved the MIP, which will assist the Company in attracting, motivating and retaining key personnel and will align the interests of participants with those of stockholders.

MIP Restricted Stock Units

The MIP allows for the issuance of restricted stock unit awards that generally may not be sold or otherwise transferred until certain restrictions have lapsed. The compensation cost related to these awards is based on the grant date fair value and is expensed over the requisite service period.

In January 2018, the Company granted 78,190 time-based restricted stock unit ("RSU") awards to executives and certain management-level employees with a grant-date fair value of $19.50 per unit and a vesting period of three years. In September 2018, the Company granted an additional 126,660 time-based RSU awards to executives and certain management-level employees with a grant-date fair value of $21.01 per unit and a vesting period of three years. The additional grants were issued as replacement awards as a result of the cancellation of certain total shareholder return ("TSR") performance restricted stock unit awards, as further discussed below.

In March 2018, a director was granted 5,893 time-based restricted stock unit awards with a grant-date fair value of $11.99 per unit of which 1,474 units vested immediately and the remaining 4,419 units will vest over a period of three years. In September 2018, the Company granted an additional 36,513 time-based RSU awards to its directors with a grant-date fair value of $5.45 per unit which will vest over a period of three years.

The following table summarizes our time-based RSUs as of September 30, 2018:

	Time-Based Restricted Stock Units	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2017	7,500	$ 19.50
Granted	247,256	$ 18.02
Forfeited	(4,146)	$ 19.93
Vested	(2,651)	$ 15.55
Non-vested at September 30, 2018	247,959	$ 18.06

We expense time-based RSUs on a straight-line basis over the requisite service period. As of September 30, 2018, the total remaining unearned compensation related to non-vested time-based RSUs was $3.9 million, which will be amortized over the weighted-average remaining service period of 2.2 years.

In January 2018, the Company granted 191,390 shares total shareholder return ("TSR") performance restricted stock unit awards to executives and certain management-level employees. As discussed above, in September 2018, the Company canceled all unvested TSR performance restricted stock units. Immediately after the cancellation, the Company issued replacement awards consisting of 126,660 time-based RSUs and 63,330 TSR performance RSUs, assuming target performance.

The TSR performance RSUs would vest assuming achievement of the goals at target level. Awards of TSR performance RSUs will be earned based on a predefined performance criteria determined by comparing our total shareholder return during a three-year period to the respective total shareholder returns of companies in a performance peer group. Based upon our ranking in the performance peer group, a recipient of TSR performance RSUs may earn a total award ranging from 0% to 200% of the initial grant. The TSR modifier is considered a market condition. The awards are also subject to certain other performance conditions which were considered in calculating the grant date fair value.

We estimated the fair value of TSR Performance RSUs at the modification date using a Monte Carlo simulation. Assumptions used in the Monte Carlo simulation were as follows:

	TSR Performance RSU Replacement Awards
Modification Date	September 11, 2018
Remaining Performance period	2.31 years
VNR Closing Price	$5.40
VNR Beginning TSR Price	$19.00
Compounded Risk-Free Interest Rate (2.31-yr)	2.75%
VNR Historical Volatility (2.31-yr)	71.69%
Fair value of unit	$19.76

We recognize compensation expense on a straight-line basis over the requisite service period. As of September 30, 2018, total remaining unearned compensation related to TSR performance RSUs was $1.2 million, which will be amortized over the weighted-average remaining service period of 2.3 years.

Share-based compensation for the predecessor and successor periods are not comparable. Our condensed consolidated statements of operations reflect non-cash compensation related to our MIP of $0.6 million and $1.7 million for the three and nine months ended September 30, 2018 (Successor), respectively, and non-cash compensation related to the Predecessor Incentive Plan of $0.7 million and $5.8 million for the one and seven months ended July 31, 2017 (Predecessor), respectively. There was no non-cash compensation expense during the two months ended September 30, 2017 (Predecessor).

13. Income Taxes

For the nine months ended September 30, 2018, we recorded no income tax expense or benefit. The difference between our effective tax rate and the federal statutory income tax rate of 21% is primarily due to the effect of changes in the Company's valuation allowance. During the nine months ended September 30, 2018, the Company has continued to record a full valuation allowance against its deferred tax position. A valuation allowance has been recorded as management does not believe that it is more-likely-than-not that its deferred tax assets will be realized.

On December 22, 2017, President Trump signed into law the Tax Act that significantly reforms the U.S. tax code. Our accounting for the Tax Act is incomplete. However, as noted in our 2017 Annual Report, at December 31, 2017 we were able to reasonably estimate certain effects and, therefore, recorded provisional adjustments associated with the reduction of U.S. federal corporate tax rate, changes in net operating loss utilization, and immediate expensing of certain capital investments. We have not made any additional measurement-period adjustments related to these items during the quarter. We are continuing to gather additional information to complete our accounting for these items and expect to complete our accounting within the prescribed measurement period.

14. Subsequent Events

Asset Sale

On October 15, 2018, we completed the Arkansas Divestment for a total consideration of $10.8 million, subject to customary post-closing adjustments. Subsequent to the completion of the Arkansas Divestment, the borrowing base under our Successor Credit Facility was reduced to $689.0 million.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to assist in understanding our results of operations for the three and nine months ended September 30, 2018 (Successor) and for the period from August 1, 2017 through September 30, 2017 (Successor) and January 1, 2017 through July 31, 2017 (Predecessor), and should be read in conjunction with our unaudited condensed consolidated financial statements and the notes thereto included in this Quarterly Report and with the condensed consolidated financial statements, notes and management's discussion and analysis of financial condition and results of operations included in our 2017 Annual Report. As described below, however, such prior financial statements may not be comparable to our interim financial statements due to the adoption of fresh-start accounting.

As discussed in Note 1 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item 1 of this report, the Company applied fresh-start accounting upon emergence from bankruptcy on August 1, 2017, using a Convenience Date of July 31, 2017, at which time it became a new entity for financial reporting purposes. References to the Successor relate to the Company on and subsequent to the Effective Date. References to Predecessor refer to the Company prior to the Effective Date.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed. For more information, see "Forward-Looking Statements."

Overview

We are an exploration and production company engaged in the production and development of oil and natural gas properties in the United States. The Company is currently focused on adding value by efficiently operating our producing assets and, in certain areas, applying modern drilling and completion technologies in order to fully assess and realize potential development upside. Our primary business objective is to increase shareholder value by growing reserves, production and cash flow in a capital efficient manner. Through our operating subsidiaries, as of September 30, 2018, we own properties and oil and natural gas reserves primarily located in nine operating basins:

- the Green River Basin in Wyoming;
- the Piceance Basin in Colorado;
- the Permian Basin in West Texas and New Mexico;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Gulf Coast Basin in Texas, Louisiana and Alabama;
- the Big Horn Basin in Wyoming and Montana;
- the Anadarko Basin in Oklahoma and North Texas;
- the Wind River Basin in Wyoming; and
- the Powder River Basin in Wyoming.

As of September 30, 2018, based on internal reserve estimates, our total estimated proved reserves were 1,724.2 Bcfe, including 35 Bcfe related to assets held for sale, of which approximately 72% were natural gas reserves, 15% were oil reserves and 13% were NGLs reserves. Of these total estimated proved reserves, approximately 64%, or 1,109.3 Bcfe, were classified as proved developed. Also, at September 30, 2018, we owned working interests in 10,888 gross (3,696 net) productive wells. Our operated wells accounted for approximately 43% of our total estimated proved reserves at September 30, 2018. Our average net daily production for the nine months ended September 30, 2018 (Successor), the five months ended December 31, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor) was 353 MMcfe/day, 364 MMcfe/day and 381 MMcfe/day, respectively.

As of September 30, 2018, the present value of estimated future net revenues to be generated from the production of proved reserves (“PV-10”) determined in accordance with the rules and regulations of the Securities and Exchange Commission (“SEC”) (using the 12-month unweighted average of first-day-of-the-month price, the “12-month average price”) was approximately $1.3 billion. The PV-10 calculated in accordance with the terms of the second lien notes indenture, (using modified ACNTA pricing based on the five-year forward strip price quoted on the NYMEX, and adjusted to give effect to our commodity derivative contracts in place as of September 30, 2018) was approximately $1.0 billion. The foregoing reflect the Company’s unaudited estimates based on internal records and other data currently available to the Company, have been compiled by the Company in good faith, and are subject to revision. Accordingly, investors should not place undue reliance on such estimates.

We develop an annual capital expenditures budget which is reviewed and approved by our Board of Directors (the “Board”) and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow, commodity prices for oil and natural gas and externally available sources of financing, such as bank debt, asset divestitures, issuance of debt and equity securities, and strategic joint ventures, when establishing our capital expenditure budget.
Our revenues and operating cash flow depend on the successful development of our inventory of capital projects with available capital, the volume and timing of our production, as well as commodity prices for oil and natural gas. Such pricing factors are largely beyond our control; however, we have historically employed commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Asset Divestitures

During 2018, we completed the sale of certain oil and natural gas properties in the Permian Basin, the Green River Basin and in Mississippi. We also sold our working interests in related oil and natural gas producing properties located in multiple counties in Texas, Louisiana and Colorado. Additionally, we completed the Potato Hills Divestment during the third quarter of 2018. Net cash proceeds received from the sale of all of these properties were approximately $92.2 million, subject to customary post-closing adjustments. Additionally, we incurred costs to sell of approximately $2.4 million. The net cash proceeds from these divestments were used to reduce borrowings under our Successor Credit Facility.

On October 15, 2018, we closed the sale of our Arkoma Basin properties in Arkansas, which comprise all of our interests located within the state (the “Arkansas Divestment”). Net cash proceeds received from the sale of these properties were approximately $10.8 million, subject to customary post-closing adjustments.

Additionally, we are in the process of publicly marketing our Greater East Haynesville divestment package which includes certain oil and natural gas properties in East Texas and North Louisiana. The properties include operated and non-operated working interests, with current production of approximately 2,500 Boe per day, and associated development rights.

We continue to progress other asset sale processes and are actively preparing additional assets for potential divestment. The sales of these properties are anticipated to further reduce debt under our Successor Credit Facility and sharpen the focus of the portfolio.

Emergence from Voluntary Reorganization under Chapter 11 Proceedings

On February 1, 2017, the Predecessor and certain of its subsidiaries filed voluntary petitions (collectively, the “Bankruptcy Petitions” and, the cases commenced thereby, the “Chapter 11 Cases”) for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas. The Chapter

11 Cases were administered under the caption “In re Vanguard Natural Resources, LLC, et al.”

Also upon emergence from bankruptcy, we made multiple changes to our accounting policies including the application of fresh-start accounting. Please read Note 1 of the Notes to the Consolidated Financial Statements included under Part II, Item 8 of our 2017 Annual Report for a discussion of the accounting policy changes.

Capital Development

Total capital expenditures were approximately $104.6 million during the nine months ended September 30, 2018. We currently anticipate a total capital expenditures budget ranging from $120.0 million to $125.0 million for the full year of 2018, down from our August 2018 guidance. This capital decrease is primarily due to a decrease in drilling activity in Vanguard’s lease hold in Pinedale and timing changes across other areas in the portfolio.

In the Green River Basin, we are on track to spend between $7.0 million and $8.0 million in the Pinedale Field in Wyoming for the remainder of 2018, where we participate in the drilling of vertical natural gas wells with partners Ultra Petroleum Corporation and Pinedale Energy Partners. In the Arkoma Basin we expect to spend approximately $7.0 million of our remaining 2018 capital budget where we will be participating as a non-operated partner with Newfield Exploration Company in a one rig program, drilling and completing horizontal Woodford wells. The balance of our remaining drilling and completion capital will be spent on production uplift projects in the Permian and Big Horn Basins.

During the nine months ended September 30, 2018, we drilled and completed 21 gross (20.5 net) operated wells. In addition, we participated in the drilling of 151 gross (18.1 net) non-operated wells and in the completion of 120 gross (15.6 net) non-operated wells.

Results of Operations

As previously discussed, in addition to adopting fresh-start accounting, the Successor also adopted the successful efforts method of accounting as of July 31, 2017. Prior to July 31, 2017, the Predecessor used the full-cost method of accounting. Further, in conjunction with the application of fresh-start accounting, we adopted ASC Topic 606. The results of operations of the Successor and the Predecessor are not comparable.

Three Months Ended September 30, 2018, Two Months Ended September 30, 2017 and One Month Ended July 31, 2017

The table included below sets forth financial and operating data for the periods indicated (in thousands). The two months ended September 30, 2017 (Successor) and the one month ended July 31, 2017 (Predecessor) are distinct reporting periods as a result of our application of fresh-start accounting at the Convenience Date and may not be comparable to prior periods.

	Successor[a]		Predecessor[a]
	Three Months Ended September 30, 2018	Two Months Ended September 30, 2017	One Month Ended July 31, 2017
Revenues:			
Oil sales	$42,909	$27,303	$ 11,820
Natural gas sales	46,448	39,032	4,412
NGLs sales	27,073	13,465	4,792
Oil, natural gas and NGLs sales	116,430	79,800	21,024
Net losses on commodity derivative contracts	(30,887)	(32,352)	(12,019)
Total revenues and losses on commodity derivative contracts	$85,543	$47,448	$ 9,005
Costs and expenses:			
Production:			
Lease operating expenses	35,424	26,447	11,787
Transportation, gathering, processing, and compression	9,551	8,044	—
Production and other taxes	9,748	5,737	1,983
Depreciation, depletion, amortization, and accretion	35,568	27,578	7,328
Impairment of oil and natural gas properties	1,965	—	—
Exploration expense	219	105	—
Selling, general and administrative expenses	10,152	7,194	8,027
Non-cash compensation	581	—	711
Total costs and expenses	$103,208	$75,105	$ 29,836
Other income (expense):			
Interest expense	(16,060)	(9,615)	(5,003)
Net gains on divestitures of oil and natural gas properties	1,747	—	—
Other	614	36	472
Reorganization items	(732)	—	988,452

(a) During the three months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the one month ended July 31, 2017 (Predecessor), we divested certain oil and natural gas properties and related assets. As such, there are no operating results from these properties included in our operating results from the closing date of the divestitures forward.

Revenues

Oil, natural gas and NGLs sales were $116.4 million, $79.8 million, and $21.0 million for the three months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor), and the one month ended July 31, 2017 (Predecessor), respectively. The key oil, natural gas and NGLs revenue measurements were as follows:

	Successor[(a)]		Predecessor[(a)]
	Three Months Ended September 30, 2018	Two Months Ended September 30, 2017	One Month Ended July 31, 2017
Average realized prices, excluding hedges:			
Oil (Price/Bbl)	$58.14	$ 43.70	$ 40.32
Natural Gas (Price/Mcf) [(b)]	$2.18	$ 2.51	$ 0.53
NGLs (Price/Bbl) [(b)]	$35.19	$ 25.82	$ 17.09
Average realized prices, including hedges[(c)]:			
Oil (Price/Bbl)	$37.25	$ 40.45	$ 40.32
Natural Gas (Price/Mcf)	$2.13	$ 2.63	$ 0.53
NGLs (Price/Bbl)	$26.71	$ 21.90	$ 17.09
Average NYMEX prices:			
Oil (Price/Bbl)	$69.48	$ 48.94	$ 46.68
Natural Gas (Price/Mcf)	$2.90	$ 2.97	$ 3.07
Total production volumes:			
Oil (MBbls)	738	625	293
Natural Gas (MMcf)	21,319	15,537	8,353
NGLs (MBbls)	769	521	280
Combined (MMcfe)	30,363	22,414	11,794
Average daily production volumes:			
Oil (Bbls/day)	8,022	10,242	9,456
Natural Gas (Mcf/day)	231,729	254,702	269,450
NGLs (Bbls/day)	8,361	8,548	9,043
Combined (Mcfe/day)	330,028	362,402	380,447

(a) During the three months ended September 30, 2018 (Successor), two months ended September 30, 2017 (Successor) and the one month ended July 31, 2017 (Predecessor), we divested certain oil and natural gas properties and related assets. As such, there are no operating results from these properties included in our operating results from the closing date of the divestitures forward.

(b) In accordance with the adoption of ASC Topic 606, the average realized natural gas and NGLs prices for the three months ended September 30, 2018 exclude gathering, transportation, and processing fees of $9.6 million related to certain of our natural gas and NGLs marketing and processing agreements that were reclassified and presented as Transportation, gathering, processing, and compression expense in our condensed consolidated statements of operations. As such, our average realized prices are not comparable with the prior period. If our natural gas and NGLs revenues are shown net of these fees, the average realized natural gas price excluding hedges would be $1.87 per Mcf and the average NGLs price excluding hedges would be $31.21 per Bbl for the three months ended September 30, 2018.

(c) Excludes the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period.

The overall increase in oil and NGLs sales during the three months ended September 30, 2018 (Successor) compared to the same period in 2017, was primarily due to the increase in the average realized oil price, excluding hedges. The increase in realized oil price is primarily due to a higher average NYMEX crude oil price, which increased 44% as compared to the same period in 2017. Our realized oil prices were also impacted by regional basis differentials. Industry activity is heavily focused in the Permian Basin, and as a result, Midland Cushing crude oil differentials have widened during 2018. Average daily production decreased to approximately 330 MMcfe/day for the three months ended September 30, 2018 (Successor) from approximately 362 MMcfe/day for the two months ended September 30, 2017 (Successor), and 380 MMcfe/day the one month ended July 31, 2017 (Predecessor). As discussed above, the adoption of ASC Topic 606 also increased natural gas and NGLs revenue by $9.6 million during the Successor period due to the reclassification of gathering, transportation, and processing fees.

Refer to Note 4 to the Condensed Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report for further details.

On a Mcfe basis, crude oil, natural gas and NGLs accounted for 15%, 70% and 15%, respectively, of our production during the three months ended September 30, 2018 (Successor) compared to 16%, 70% and 14%, respectively, of our production during the same period in 2017 (Predecessor).

Hedging and Price Risk Management Activities

We recognized a net loss on commodity derivative contracts of $30.9 million, $32.4 million, and $12.0 million for the three months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor), and the one month ended July 31, 2017 (Predecessor), respectively. Our hedging program historically helped mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and we pay the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because our hedges are currently not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected in our condensed consolidated statement of operations in the net gains or losses on commodity derivative contracts line item. However, these fair value changes that are reflected in the condensed consolidated statement of operations reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and again the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and other customary charges. Lease operating expenses were $35.4 million for the three months ended September 30, 2018 (Successor), $26.4 million for the two months ended September 30, 2017 (Successor), and $11.8 million the one month ended July 31, 2017 (Predecessor). Lease operating expenses remained consistent period over period despite the divestitures completed during 2017 and 2018 mainly due to increased well workovers performed in the Gulf Coast and Permian Basins during the three months ended September 30, 2018.

Transportation, gathering, processing and compression fees represent third-party costs related to certain of our natural gas and NGLs marketing and processing agreements. These expenses were $9.6 million for the three months ended September 30, 2018 (Successor) and $8.0 million for the two months ended September 30, 2017 (Successor), due to the adoption of ASC Topic 606 in conjunction with fresh-start accounting. Prior to August 1, 2017, these costs were included in the net proceeds received from processing; however, natural gas and NGLs revenues and related marketing and processing costs are recognized on a gross basis effective August 1, 2017. Refer to Note 4 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report for further details.

Production and other taxes include severance, ad valorem and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state or county and are based on the value of our reserves. As a percentage of wellhead revenues, production and other taxes was 8.4%, 7.2% and 9.4% for the three months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor), and the one month ended July 31, 2017 (Predecessor), respectively. The percentage was lower during the successor period primarily due to higher natural gas and NGLs revenues as they were presented gross of gathering, transportation, and processing fees of $9.6 million related to certain of our natural gas and NGLs marketing and processing agreements with the adoption of ASC Topic 606. Natural gas and NGLs revenues prior to August 1, 2017 were presented net of these fees. We record and remit production taxes based on net proceeds received from processing related to these contracts. When using net proceeds in the calculation, the effective tax rate for the current period is 9.1%.

Depreciation, depletion, amortization, and accretion expense was $35.6 million, $27.6 million and $7.3 million for the three months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor), and the one month ended July 31, 2017 (Predecessor), respectively. The increase in depreciation, depletion, amortization, and accretion expense is due to a higher amortization base as a result of the application of fresh-start accounting which led to a corresponding increase in the depletion rate per equivalent unit of production for the Successor period.

We adjust our depletion rate on oil and natural gas properties each quarter for significant changes in our estimates of oil and natural gas reserves and costs. Thus, our depletion rate could change significantly in the future. Depletion expense is not comparable between the Successor and Predecessor periods as a result of our implementation of fresh-start accounting upon emergence from bankruptcy, whereupon the carrying value of our proved oil and gas properties on our balance sheet was recorded at fair value. Also upon emergence, we changed our method of accounting for oil and gas exploration and development activities from the full-cost method to the successful-efforts method of accounting.

An impairment of oil and natural gas properties of $2.0 million was recognized during the three months ended September 30, 2018 (Successor). The impairment charge is related to the Arkansas Divestment properties classified as assets held for sale at September 30, 2018. The net book value exceeded the net proceeds.

Selling, general and administrative expenses (excluding non-cash compensation) include the costs of our employees, related benefits, office leases, professional fees and other costs not directly associated with field operations. During the three months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor), and the one month ended July 31, 2017 (Predecessor), selling, general and administrative expenses were $10.2 million, $7.2 million, and $8.0 million, respectively. Selling, general and administrative expenses in 2017 were impacted by costs incurred in connection with the Chapter 11 Cases, which are primarily included in “Reorganization Items” on our Condensed Consolidated Statement of Operations.

In addition, we incurred non-cash compensation expense of $0.6 million for the three months ended September 30, 2018 (Successor) and $0.7 million the one month ended July 31, 2017 (Predecessor), respectively.

Other Income and Expense

Interest expense was $16.1 million, $9.6 million and $5.0 million during the three months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor), and the one month ended July 31, 2017 (Predecessor), respectively. Interest expense was lower during the Predecessor period primarily due to the discontinuance of interest on the Predecessor Company’s senior notes that were canceled as part of its Chapter 11 Cases.

During the three months ended September 30, 2018 (Successor), the Company recorded a net gain of approximately $1.7 million on the sale of oil and natural gas properties.

Reorganization Items

We incurred reorganization costs of $0.7 million for the three months ended September 30, 2018 (Successor). Reorganization items include expenses, gains and losses that are the result of the reorganization and restructuring of the business. Professional fees included in reorganization items represent professional fees for post-petition expenses. Reorganization costs incurred subsequent to the Emergence Date of $0.9 million are recorded in the selling, general and administrative expenses line item in the Company’s unaudited consolidated statements of operations for the two months ended September 30, 2017 (Successor). We also incurred a reorganization gain of $988.5 million for the one month ended July 31, 2017 (Predecessor) as a result of the gain on the discharge of debt and fresh-start adjustments upon emergence from Chapter 11 bankruptcy. See Note 3, “Fresh-Start Accounting” to the consolidated financial statements for further details.

Nine Months Ended September 30, 2018, Two Months Ended September 30, 2017 and Seven Months Ended July 31, 2017

The table included below sets forth financial and operating data for the periods indicated (in thousands). The two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor) are distinct reporting periods as a result of our application of fresh-start accounting at the Convenience Date and may not be comparable to prior periods.

	Successor [a]		Predecessor [a]
	Nine Months Ended September 30, 2018	Two Months Ended September 30, 2017	Seven Months Ended July 31, 2017
Revenues:			
Oil sales	$135,523	$27,303	$ 97,496
Natural gas sales	144,338	39,032	113,587
NGLs sales	71,557	13,465	35,565
Oil, natural gas and NGLs sales	351,418	79,800	246,648
Net losses on commodity derivative contracts	(94,804)	(32,352)	(24,887)
Total revenues and losses on commodity derivative contracts	$256,614	$47,448	$ 221,761
Costs and expenses:			
Production:			
Lease operating expenses	103,182	26,447	87,092
Transportation, gathering, processing and compression	30,821	8,044	—
Production and other taxes	27,500	5,737	21,186
Depreciation, depletion, amortization, and accretion	114,318	27,578	58,384
Impairment of oil and natural gas properties	24,118	—	—
Exploration expense	1,965	105	—
Selling, general and administrative expenses	32,922	7,194	28,099
Non-cash compensation	1,655	—	711
Total costs and expenses	$336,481	$75,105	$ 195,472
Other income (expense):			
Interest expense	$(46,683)	$(9,615)	$ (35,276)
Net gains on interest rate derivative contracts	—	—	30
Net gains on divestitures of oil and natural gas properties	6,647	—	—
Other	588	36	783
Reorganization items	(3,049)	—	908,485

(a) During the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), we divested certain oil and natural gas properties and related assets. As such, there are no operating results from these properties included in our operating results from the closing date of the divestitures forward.

Revenues

Oil, natural gas and NGLs sales were $351.4 million, $79.8 million, and $246.6 million for the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor), and the seven months ended July 31, 2017 (Predecessor), respectively. The key oil, natural gas and NGLs revenue measurements were as follows:

	Successor[(a)]		Predecessor[(a)]
	Nine Months Ended September 30, 2018	Two Months Ended September 30, 2017	Seven Months Ended July 31, 2017
Average realized prices, excluding hedges:			
Oil (Price/Bbl)	$57.52	$ 43.70	$ 43.33
Natural Gas (Price/Mcf)[(b)]	$2.11	$ 2.51	$ 2.05
NGLs (Price/Bbl)[(b)]	$30.48	$ 25.82	$ 17.87
Average realized prices, including hedges[(c)]:			
Oil (Price/Bbl)	$39.94	$ 40.45	$ 43.34
Natural Gas (Price/Mcf)	$2.22	$ 2.63	$ 2.05
NGLs (Price/Bbl)	$23.86	$ 21.90	$ 17.87
Average NYMEX prices:			
Oil (Price/Bbl)	$66.62	$ 48.94	$ 49.72
Natural Gas (Price/Mcf)	$2.89	$ 2.97	$ 3.22
Total production volumes:			
Oil (MBbls)	2,356	625	2,250
Natural Gas (MMcf)	68,263	15,537	55,375
NGLs (MBbls)	2,348	521	1,990
Combined (MMcfe)	96,485	22,414	80,814
Average daily production volumes:			
Oil (Bbls/day)	8,630	10,242	10,613
Natural Gas (Mcf/day)	250,048	254,702	261,201
NGLs (Bbls/day)	8,600	8,548	9,387
Combined (Mcfe/day)	353,424	362,402	381,198

(a) During the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), we divested certain oil and natural gas properties and related assets. As such, there are no operating results from these properties included in our operating results from the closing date of the divestitures forward.

(b) In accordance with the adoption of ASC Topic 606, the average realized natural gas and NGLs prices for the nine months ended September 30, 2018 exclude gathering, transportation, and processing fees of $30.8 million related to certain of our natural gas and NGLs marketing and processing agreements that were reclassified and presented as Transportation, gathering, processing, and compression expense in our condensed consolidated statements of operations. As such, our average realized prices are not comparable with the prior period. If our natural gas and NGLs revenues are shown net of these fees, the average realized natural gas price excluding hedges would be $1.79 per Mcf and the average NGLs price excluding hedges would be $26.92 per Bbl for the nine months ended September 30, 2018.

(c) Excludes the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period.

The overall increase in oil and NGLs sales during the nine months ended September 30, 2018 (Successor) compared to the same period in 2017 was primarily due in part to the increase in the average realized oil prices, excluding hedges. The increase in average realized oil price is primarily due to a higher average NYMEX crude oil price, which increased 35% as compared to the same period in 2017. Our realized oil prices were also impacted by regional basis differentials. Industry activity is heavily focused in the Permian Basin, and as a result Midland Cushing crude oil differentials have widened during 2018. As discussed above, the adoption of ASC Topic 606 also increased natural gas and NGLs revenue by $30.8 million during the nine months ended September 30, 2018 (Successor) due to the reclassification of gathering, transportation, and processing fees. Refer to Note 4 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item I of this Quarterly Report for further details.

The increase in sales due to higher average realized oil price and the change in presentation was partially offset by a decrease in average realized natural gas price, primarily due to a lower average NYMEX natural gas price, which decreased 9%, as compared to the same period in 2017. This decrease in realized pricing is attributable not only to a decrease in NYMEX pricing but also the widening in regional basis differentials during 2018, specifically Rockies gas basis, which is approximately 70% of our total natural gas production. The increase in sales due to higher average realized oil price and the change in presentation was also partially offset by an overall decrease in average daily production which decreased to approximately 353 MMcfe/day for the nine months ended September 30, 2018 (Successor) from approximately 362 MMcfe/day and 381 MMcfe/day for the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. The decrease in average daily production was primarily due to divestitures completed during 2017 and 2018.

On a Mcfe basis, crude oil production accounted for 15%, 17% and 17% of our production during the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. Natural gas accounted for 71%, during the nine months ended September 30, 2018 (Successor) compared to 69% and 68% for the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. On a Mcfe basis, NGLs production accounted for 14%, 14%, and 15% of our production during the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively.

Hedging and Price Risk Management Activities

We recognized a net loss on commodity derivative contracts of $94.8 million, $32.4 million and $24.9 million, during the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. Our hedging program is intended to mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and we pay the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because our hedges are currently not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected in our condensed consolidated statement of operations in the net gains or losses on commodity derivative contracts line item. However, these fair value changes that are reflected in the condensed consolidated statement of operations reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and again the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and other customary charges. Lease operating expenses were $103.2 million, $26.4 million and $87.1 million, for the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. The decrease in lease operating expenses is primarily due to lower production volumes as a result of decreased operational activity and divestitures completed in 2017 and 2018.

Transportation, gathering, processing and compression fees represent third-party costs related to certain of our natural gas and NGLs marketing and processing agreements. These expenses were $30.8 million for the nine months ended September 30, 2018 (Successor) and $8.0 million for the two months ended September 30, 2017 (Successor) due to the adoption of ASC Topic 606 in conjunction with fresh-start accounting. Prior to August 1, 2017, these costs were included in the net proceeds received from processing; however, natural gas and NGLs revenues and related marketing and processing costs are recognized on a gross basis effective August 1, 2017. Refer to Note 4 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report for further details.

Production and other taxes include severance, ad valorem and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state or county and are based on the value of our reserves. As a percentage of wellhead revenues, production and other taxes was 7.8%, 7.2% and 8.6% for the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. The percentage was lower during the Successor period primarily due to higher natural gas and NGLs revenues as they were presented gross of gathering, transportation, and processing fees of $30.8 million related to certain of our natural gas and NGLs marketing and processing agreements with the adoption of ASC Topic 606. Natural gas and NGLs revenues prior to August 1, 2017 were presented net of these fees. We record and remit production taxes based on net proceeds received from processing related to these contracts. When using net proceeds in the calculation, the effective tax rate for the current period is 8.6%

Depreciation, depletion, amortization, and accretion expense was $114.3 million, $27.6 million and $58.4 million for the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. The increase in depreciation, depletion, amortization, and accretion expense is due to a higher amortization base as a result of the application of fresh-start accounting which led to a corresponding increase in the depletion rate per equivalent unit of production for the Successor period.

We adjust our depletion rate on oil and natural gas properties each quarter for significant changes in our estimates of oil and natural gas reserves and costs. Thus, our depletion rate could change significantly in the future. Depletion expense is not comparable between Successor and Predecessor periods as a result of our implementation of fresh-start accounting upon emergence from bankruptcy, whereupon the carrying value of our proved oil and gas properties on our balance sheet was recorded at fair value. Also upon emergence, we changed our method of accounting for oil and gas exploration and development activities from the full-cost method to the successful-efforts method of accounting.

An impairment of oil and natural gas properties of $24.1 million was recognized during the nine months ended September 30, 2018 (Successor). The impairment charge relates primarily to downward revisions in our unproved property leasehold acreage and working interest in certain of our undeveloped leasehold and the reduction in value of certain of our operating districts due to a decline in forward natural gas prices.

Selling, general and administrative expenses (excluding non-cash compensation) include the costs of our employees, related benefits, office leases, professional fees and other costs not directly associated with field operations. During the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively, selling, general and administrative expenses were $32.9 million, $7.2 million, and $28.1 million, respectively. The decrease is primarily due to management severance payments made during the two months ended September 30, 2017 (Successor). Selling, general and administrative expenses in 2017 were impacted by costs incurred in connection with the Chapter 11 Cases, which are primarily included in “Reorganization Items” on our Condensed Consolidated Statement of Operations.

In addition, we incurred non-cash compensation expense of $1.7 million and $0.7 million for the nine months ended September 30, 2018 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. The increase is primarily due to a higher grant date fair value of the restricted stock unit awards as compared to the grant date fair value of the awards that were granted under the Predecessor Incentive Plan.

Other Income and Expense

Interest expense was $46.7 million, $9.6 million, and $35.3 million during the nine months ended September 30, 2018 (Successor), the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively.

During the nine months ended September 30, 2018 (Successor), the Company recorded a net gain of approximately $6.6 million on the sale of oil and natural gas properties.

Reorganization Items

We incurred reorganization costs of $3.0 million for the nine months ended September 30, 2018 (Successor). Reorganization items include expenses, gains and losses that are the result of the reorganization and restructuring of the business. Professional fees included in reorganization items represent professional fees for post-petition expenses. Reorganization costs incurred subsequent to the Emergence Date of $0.9 million are recorded in the selling, general and administrative expenses line item in the Company’s unaudited consolidated statements of operations for the two months ended September 30, 2017 (Successor). We also incurred a reorganization gain of $908.5 million for the seven months ended July 31, 2017 (Predecessor) as a result of the gain on the discharge of debt and fresh-start adjustments upon emergence from Chapter 11 bankruptcy. See Note 3, “Fresh-Start Accounting” to the consolidated financial statements for further details.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States (“GAAP”) requires management to select and apply accounting policies that best provide the framework to report our results of operations and financial position. The selection and application of those policies requires management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of September 30, 2018, our critical accounting policies discussed in Note 1 of the Notes to the Condensed Consolidated Financial Statements included under Part 1, Item 1 of this Quarterly Report are consistent with those discussed in Note 1 of the Notes to the Consolidated Financial Statements included under Part II, Item 8 of our 2017 Annual Report.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGLs reserves and related future cash flows, the fair value of derivative contracts and asset retirement obligations, accrued oil, natural gas and NGLs revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization, and accretion expense, income taxes, and non-cash compensation. Actual results could differ from those estimates.

Liquidity and Capital Resources

Overview

Historically, we have obtained financing through proceeds from bank borrowings, cash flow from operations and from the public equity and debt markets to provide us with the capital resources and liquidity necessary to operate our business. We have also engaged in asset sales and used the resulting proceeds to reduce our indebtedness. To date, the primary use of capital has been for the development of oil and natural gas properties. Our future success in growing reserves, production and cash flow will be highly dependent on the capital resources available to us, our inventory of executable well locations and our success in drilling for additional reserves. We expect to fund our capital expenditures with cash flow from operations. For the remainder of 2018, we expect our primary funding sources to be cash flows generated by operating activities, available borrowing capacity under the Successor Credit Facility and/or proceeds from the divestiture of assets. From time to time, we may explore or pursue opportunities to reorganize or refinance our capital structure

The borrowing base under the Fourth Amended and Restated Credit Agreement dated as of August 1, 2017 (the “Successor Credit Facility”) is subject to adjustments from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the lenders’ petroleum engineers utilizing the lenders’ internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and NGLs reserves. The next borrowing base redetermination is scheduled for November of 2018. Should we experience a decline in oil and natural gas prices or basis differentials widen significantly in 2018, we may, among other things, be unable to maintain or increase our borrowing capacity, or be required to repay current or future indebtedness.

At September 30, 2018, we were in compliance with all of our debt covenants. Given, in part, the current environment for commodity prices and basis differentials, we updated our internal projections to take such updates into account, and, as a result of these updated projections, we now expect that we may not be in compliance with our ratio of consolidated first lien debt to EBITDA covenant as defined within the Second Amendment to the Successor Credit Facility in certain future periods, beginning with the December 2018 reporting period. In light of these updates, we have taken a number of steps to mitigate a potential default, including (i) discussions with certain banks in our Successor Credit Facility to amend our ratio of consolidated first lien debt to EBITDA covenant, (ii) continue to pursue efforts to divest certain oil and natural gas properties to use proceeds to reduce first lien leverage and (iii) investigating refinancing alternatives. To the extent we breach the consolidated first lien debt to EBITDA covenant as defined within the Second Amendment to the Successor Credit Facility, we would be in default and the lenders would be able to accelerate the maturity of that indebtedness (which could result in an acceleration of our Senior Notes due 2024) and exercise other rights and remedies, all of which could adversely affect our operations and our ability to satisfy our obligations as they come due. These conditions raise substantial doubt about our ability to continue as a going concern within one year after the date that these financial statements are issued. While no assurances can be made that we will be able to consummate such mitigation plans, we believe the combination of the long-term global outlook for commodity prices and our mitigation efforts will be viewed positively by our lenders.

Statements of Cash Flows

The following table summarizes our primary sources and uses of cash for the periods indicated (in thousands):

	Successor		Predecessor
	Nine Months Ended September 30, 2018	Two Months Ended September 30, 2017	Seven Months Ended July 31, 2017
Net cash provided by operating activities	$62,992	$13,728	$52,288
Net cash provided by (used in) investing activities	$(19,779)	$(23,444)	$76,836
Net cash used in financing activities	$(44,814)	$(1,129)	$(151,471)

Cash Flow from Operations

Net cash provided by operating activities was approximately $63.0 million for the nine months ended September 30, 2018 (Successor) compared to $13.7 million and $52.3 million for the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. Changes in working capital increased total cash flows by $5.0 million for the nine months ended September 30, 2018 (Successor), and decreased total cash flows by $7.1 million and $1.6 million for the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. Contributing to the increase in working capital during the first nine months of 2018 was a decrease in accounts receivable related to the timing of receipts from production, offset by an increase in other current assets, a decrease in accounts payable, oil and natural gas revenue payable and accrued expenses and other current liabilities that resulted primarily from the timing effects of payments.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, natural gas and NGLs prices. Oil, natural gas and NGLs prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather, and other factors beyond our control. Future cash flow from operations will depend on our ability to maintain and increase production through our drilling program, as well as the prices received for production. We enter into derivative contracts to reduce the impact of commodity price volatility on operations. We primarily use fixed-price swaps, collars, basis swap contracts and other hedge option contracts to hedge oil and natural gas prices. See Note 7 of the Notes to the Condensed Consolidated Financial Statements, included under Part I, Item 1 of this Quarterly Report and Part I, Item 3—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk, for further discussion.

Cash Flow from Investing Activities

Net cash used in investing activities was approximately $19.8 million for the nine months ended September 30, 2018 (Successor) compared to net cash used in investing activities of approximately $23.4 million for the two months ended September 30, 2017 (Successor) and net cash provided by investing activities of approximately $76.8 million for the seven months ended July 31, 2017 (Predecessor). Net cash used in investing activities during the first nine months of 2018 (Successor) primarily included $60.8 million for the drilling and development of oil and natural gas properties and $51.0 million for deposits and prepayments related to the drilling and development of oil and natural gas properties, offset by $92.2 million in proceeds from the sale of oil and natural gas properties.

Net cash used in investing activities was approximately $23.4 million for the two months ended September 30, 2017 (Successor) and net cash provided by investing activities was approximately $76.8 million for the seven months ended July 31, 2017 (Predecessor), respectively. The primary source of net cash provided by investing activities was the $126.4 million in proceeds from the sale of oil and natural gas properties for the seven months ended July 31, 2017 (Predecessor) offset by $23.7 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties and $25.7 million for additions to our oil and natural gas properties.

During the two months ended September 30, 2017 (Successor), we spent $9.0 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties and $14.4 million for additions to our oil and natural gas properties.

Cash Flow from Financing Activities

Net cash used in financing activities was approximately $44.8 million for the for the nine months ended September 30, 2018 (Successor) compared to net cash used in financing activities of approximately $1.1 million and $151.5 million for the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. Net cash used in financing activities during the nine months ended September 30, 2018 (Successor) included repayments of debt of $161.3 million, offset by proceeds from our revolving credit facility of $118.5 million.

During the two months ended September 30, 2017 (Successor), cash used in financing obligation primarily included payment of debt under the lease financing obligation. The primary drivers of net cash used in financing activities for the seven months ended July 31, 2017 (Predecessor) were repayments of debt of approximately $41.6 million under the Predecessor Credit Facility, repayment of debt of $500.3 million under the Predecessor Credit Facility in accordance with the Plan and payment for debt financing costs of $9.4 million. In addition, net cash provided by financing activities included $275.0 million for proceeds from the rights offerings and second lien investment in connection with the Plan and $125.0 million for proceeds from the Successor Term Loan.

Debt and Credit Facilities

Successor Credit Facility

On the Effective Date, VNG, as borrower, entered into the Fourth Amended and Restated Credit Agreement dated as of August 1, 2017 (the “Successor Credit Facility”), by and among VNG as borrower, Citibank, N.A., as administrative agent (the “Administrative Agent”) and Issuing Bank, and the lenders party thereto. Pursuant to the Successor Credit Facility, the lenders party thereto agreed to provide VNG with an $850.0 million exit senior secured reserve-based revolving credit facility (the “Revolving Loan”). The initial borrowing base available under the Successor Credit Facility as of the Effective Date was $850.0 million and the aggregate principal amount of Revolving Loans outstanding under the Successor Credit Facility as of the Effective Date was $730.0 million. The Successor Credit Facility also includes an additional $125.0 million senior secured term loan (the “Term Loan”). On December 21, 2017, the borrowing base was reduced to $825.0 million following the completion of the sale of our properties in the Williston Basin and was further reduced to $765.2 million following the completion of the sale of certain of our oil and natural gas properties during the first half of 2018. Please see Note 5 to the Condensed Consolidated Financial Statements included in Part I of this Quarterly Report for further discussion on our divestitures.

In July 2018, the Company entered into the Second Amendment to the Successor Credit Facility (the “Second Amendment”) among the Company, the Administrative Agent and the lenders party thereto. Among other things, the Second Amendment reduced the borrowing base from $765.2 million to $729.7 million. The completion of additional divestitures in the third quarter of 2018 also resulted in the reduction of our borrowing base to $700.3 million as of September 30, 2018. Please see Note 5 to the Condensed Consolidated Financial Statements included in Part I of this Quarterly Report for further discussion on our divestitures.

At September 30, 2018, there were $662.0 million of outstanding borrowings and $38.1 million of borrowing capacity under the Successor Credit Facility, after reflecting a $0.2 million reduction in availability for letters of credit. Subsequent to the completion of the Arkansas Divestment, the borrowing base under our Successor Credit Facility was reduced to $689.0 million.

Senior Notes due 2024

On August 1, 2017, the Company issued approximately $80.7 million aggregate principal amount of the Senior Notes due 2024 to certain eligible holders of the Predecessor’s second lien notes (the “Existing Notes”) in satisfaction of their claim of approximately $80.7 million related to the Existing Notes held by such holders. The Senior Notes due 2024 were issued in accordance with the exemption from the registration requirements of the Securities Act afforded by Section 4(a)(2) of the Securities Act.

Letters of Credit

At September 30, 2018, we had unused irrevocable standby letters of credit of approximately $0.2 million. The letters are being maintained as security related to the issuance of oil and natural gas well permits to recover potential costs of repairs, modification, or construction to remedy damages to properties caused by the operator. Borrowing availability for the letters of credit was provided under our Successor Credit Facility.

Lease Financing Obligations

On October 24, 2014, as part of our acquisition of certain natural gas, oil and NGLs assets in the Piceance Basin, we entered into an assignment and assumption agreement with Banc of America Leasing & Capital, LLC., as the lead bank, whereby we acquired compressors and related facilities and assumed the related financing obligations (the “Lease Financing Obligations”). The Lease Financing Obligations were confirmed during the bankruptcy process. Certain rights, title, interest and obligations under the Lease Financing Obligations have been assigned to several lenders and are covered by separate assignment agreements, which expire on August 10, 2020 and July 10, 2021. We have the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligations also contain an early buyout option whereby the Company may purchase the equipment for $16.0 million on February 10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 4.16%.

Please refer to Note 6 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item 1of this Quarterly Report for further information regarding our debt.

Off-Balance Sheet Arrangements

At September 30, 2018, we did not have any off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on our financial position or results of operations.

Contractual Obligations

A summary of our contractual obligations as of September 30, 2018 is provided in the following table (in thousands):

	Payments Due by Year						
	2018	2019	2020	2021	2022	After 2022	Total
Management base salaries	$326	$1,305	$1,305	$—	$—	$—	$2,936
Asset retirement obligations (1)	2,778	3,855	4,048	4,250	4,463	126,768	146,162
Derivative liabilities	27,398	59,604	32,390	970	—	—	120,362
Reserve-Based Credit Facility (2)	—	—	—	662,000	—	—	662,000
Term Loan (2)	312	1,250	1,250	120,938	—	—	123,750
Senior Notes due 2024 and interest	1,816	7,265	7,265	7,265	7,265	90,106	120,982
Operating leases	334	1,211	1,149	1,170	1,205	4,503	9,572
Development commitments (3)	12,892	26,581	—	—	—	—	39,473
Firm transportation agreements (4)	205	821	410	—	—	—	1,436
Lease financing obligations (5)	1,361	5,442	4,358	1,279	—	—	12,440
Other future obligations	117	308	—	—	—	—	425
Total	$47,539	$107,642	$52,175	$797,872	$12,933	$221,377	$1,239,538

(1) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and decommissioning of our Elk Basin, Big Escambia Creek and Fairway gas plants. Please read Note 9 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report for additional information regarding our asset retirement obligations. The balance also includes $1.6 million presented as part of liabilities held for sale on the condensed consolidated balance sheet. Please read Note 5 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report for further discussion.

(2) This table does not include interest to be paid on the principal balances shown as the interest rates on our financing arrangements are variable.

(3) Represents authorized expenditures for drilling, completion and major workover projects.

(4) Represents transportation demand charges. Please read Note 10 of the Notes to the Condensed Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report for additional information regarding our firm transportation agreements.

(5) The Lease Financing Obligations are calculated based on the aggregate present value of minimum future lease payments. The amounts presented include interest payable for each year.

Non-GAAP Financial Measure

Adjusted EBITDA

We present Adjusted EBITDA in addition to our reported net income (loss) attributable to Vanguard stockholders/unitholders in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net income (loss) attributable to Vanguard stockholders/unitholders plus:

- Net income (loss) attributable to non-controlling interest.

The result is net income (loss) which includes the non-controlling interest. From this we add or subtract the following:

- Interest expense;
- Depreciation, depletion, amortization, and accretion;
- Impairment of oil and natural gas properties;
- Exploration expense;
- Change in fair value of commodity derivative contracts;
- Net gains or losses on interest rate derivative contracts;
- Net gains on divestitures of oil and natural gas properties;
- Taxes;
- Compensation related items, which include share/unit-based compensation expense, unrealized fair value of phantom units granted to officers and cash settlement of phantom units granted to officers;
- Reorganization items;
- Severance costs;
- Material costs incurred on strategic transactions; and
- Non-controlling interest amounts attributable to each of the items above which revert the calculation back to an amount attributable to the Vanguard stockholders/unitholders.

Adjusted EBITDA is used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and our operating performance and return on capital as compared to those of other companies in our industry.

Our Adjusted EBITDA should not be considered as an alternative to net income (loss), operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

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Adjusted EBITDA attributable to Vanguard stockholders/unitholders for the three months ended September 30, 2018 (Successor) was $29.7 million compared to $31.0 million and $0.2 million, for the two months ended September 30, 2017 (Successor) and the one month ended July 31, 2017 (Predecessor) respectively.

	Successor		Predecessor
	Three Months Ended September 30, 2018	Two Months Ended September 30, 2017	One Month Ended July 31, 2017
Net income (loss) attributable to Vanguard stockholders/ unitholders	$(32,133)	$(37,297)	$963,089
Add: Net income attributable to non-controlling interests	37	61	1
Net income (loss)	$(32,096)	$(37,236)	$963,090
Plus:			
Interest expense	16,060	9,615	5,003
Depreciation, depletion, amortization, and accretion	35,568	27,578	7,328
Impairment of oil and natural gas properties	1,965	—	—
Exploration expense	219	105	—
Change in fair value of commodity derivative contracts[a]	7,970	30,026	12,019
Net gains on divestitures of oil and natural gas properties	(1,747)	—	—
Taxes	—	—	158
Compensation related items	581	—	711
Reorganization items	732	—	(988,452)
Severance costs	453	—	—
Material costs incurred on strategic transactions	—	903	—
Adjusted EBITDA before non-controlling interest	29,705	30,991	(143)
Adjusted EBITDA attributable to non-controlling interest	(12)	(24)	(39)
Adjusted EBITDA attributable to Vanguard stockholders/unitholders	$29,693	$30,967	$(182)

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(a) These items are included in the net gains (losses) on commodity derivative contracts line item in the condensed consolidated statements of operations as follows:

	Successor		Predecessor
	Three Months Ended September 30, 2018	Two Months Ended September 30, 2017	One Month Ended July 31, 2017
Net cash settlements paid on matured commodity derivative contracts	$(22,917)	$(2,326)	$—
Change in fair value of commodity derivative contracts	(7,970)	(30,026)	(12,019)
Net losses on commodity derivative contracts	$(30,887)	$(32,352)	$(12,019)

Adjusted EBITDA attributable to Vanguard stockholders/unitholders for the nine months ended September 30, 2018 (Successor) was $112.1 million compared to $31.0 million and $115.2 million for the two months ended September 30, 2017 (Successor) and the seven months ended July 31, 2017 (Predecessor), respectively. The following table presents a reconciliation of consolidated net loss to Adjusted EBITDA (in thousands):

	Successor		Predecessor
	Nine Months Ended September 30, 2018	Two Months Ended September 30, 2017	Seven Months Ended July 31, 2017
Net income (loss) attributable to Vanguard stockholders/ unitholders	$(122,590)	$(37,297)	$900,298
Add: Net income attributable to non-controlling interests	226	61	13
Net income (loss)	$(122,364)	$(37,236)	$900,311
Plus:			
Interest expense	46,683	9,615	35,276
Depreciation, depletion, amortization, and accretion	114,318	27,578	58,384
Impairment of oil and natural gas properties	24,118	—	—
Exploration expense	1,965	105	—
Change in fair value of commodity derivative contracts[(a)]	44,747	30,026	24,894
Net gains on interest rate derivative contracts[(b)]	—	—	(30)
Net gains on divestitures of oil and natural gas properties	(6,647)	—	—
Taxes	—	—	(634)
Compensation related items	1,654	—	5,797
Reorganization items	3,049	—	(908,485)
Severance costs	4,554	—	—
Material costs incurred on strategic transactions	148	903	—
Adjusted EBITDA before non-controlling interest	112,225	30,991	115,513
Adjusted EBITDA attributable to non-controlling interest	(87)	(24)	(271)
Adjusted EBITDA attributable to Vanguard stockholders/unitholders	$112,138	$30,967	$115,242

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(a) These items are included in the net gains (losses) on commodity derivative contracts line item in the condensed consolidated statements of operations as follows:

	Successor		Predecessor
	Nine Months Ended September 30, 2018	Two Months Ended September 30, 2017	Seven Months Ended July 31, 2017
Net cash settlements received (paid) on matured commodity derivative contracts	$ (50,057)	$ (2,326)	$ 7
Change in fair value of commodity derivative contracts	(44,747)	(30,026)	(24,894)
Net losses on commodity derivative contracts	$ (94,804)	$ (32,352)	$ (24,887)

(b) Net gains on interest rate derivative contracts as shown on the condensed consolidated statements of operations is comprised of the following:

	Predecessor
	Seven Months Ended July 31, 2017
Cash settlements paid on interest rate derivative contracts	$ (95)
Change in fair value of interest rate derivative contracts	125
Net gains on interest rate derivative contracts	$ 30

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 oil, natural gas and NGLs prices and interest rates. The disclosures are not meant to be precise indicators of exposure, but rather indicators of potential exposure. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. Conditions sometimes arise where actual production is less than estimated, which has, and could result in over-hedged volumes. For a detailed discussion of the risk factors that relate to our potential exposure to market risks, please refer to Part I—Item 1A—Risk Factors in our 2017 Annual Report.

Commodity Price Risk

Our primary market risk exposure is in the prices we receive for our oil, natural gas and NGLs production. Realized pricing is primarily driven by prevailing spot market prices at our primary sales points and the applicable index prices. Pricing for oil, natural gas and NGLs production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control. In addition, the potential exists that if commodity prices decline to a certain level, the borrowing base for our Successor Credit Facility can be decreased at the borrowing base redetermination date to an amount lower than the amount of debt currently outstanding and, because it would be uneconomical, production could decline to levels below our hedged volumes. Furthermore, the risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase.

We routinely enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that mitigate the volatility of future prices received as follows:

- Fixed-price swaps - where we will receive a fixed-price for our production and pay a variable market price to the contract counterparty.
- Basis swap contracts - which guarantee a price differential between the NYMEX prices and our physical pricing points. We receive a payment from the counterparty or make a payment to the counterparty for the difference between the settled price differential and amounts stated under the terms of the contract.
- Collars - where we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor (long put) on a notional quantity.

In deciding which type of derivative instrument to use, our management considers the relative benefit of each type against any cost that would be incurred, prevailing commodity market conditions and management’s view on future commodity pricing. The amount of oil and natural gas production which is hedged is determined by applying a percentage to the expected amount of production in our most current reserve report in a given year. Typically, management intends to hedge 75% to 90% of projected oil and natural gas production from proved developed producing reserves up to a three to four year period. These activities are intended to support our realized commodity prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We have also entered into fixed-price swaps derivative contracts to cover a portion of our NGLs production to reduce exposure to fluctuations in NGLs prices. However, a liquid, readily available and commercially viable market for hedging NGLs has not developed in the same way that exists for crude oil and natural gas. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits our ability to hedge our NGL production effectively or for extended periods of time. It is never management’s intention to hold or issue derivative instruments for speculative trading purposes. Management will consider liquidating a derivative contract, if they believe that they can take advantage of an unusual market condition allowing them to realize a current gain and then have the ability to enter into a new derivative contract in the future at or above the commodity price of the contract that was liquidated.

At September 30, 2018, the fair value of commodity derivative contracts was a liability of approximately $109.2 million, of which $70.0 million settles during the next twelve months.

The following tables summarize oil, natural gas and NGLs commodity derivative contracts in place at September 30, 2018.

	October 1 - December 31, 2018	Year 2019	Year 2020	Year 2021
Gas Positions:				
Fixed-Price Swaps:				
Notional Volume (MMBtu)	16,928,000	52,539,000	47,227,500	—
Fixed Price ($/MMBtu)	$ 2.89	$ 2.79	$ 2.75	$ —
Collars:				
Notional Volume (MMBtu)	—	4,125,000	5,490,000	1,825,000
Floor Price ($/MMBtu)	$ —	$ 2.60	$ 2.60	$ 2.60
Ceiling Price ($/MMBtu)	$ —	$ 3.00	$ 3.00	$ 3.07

	October 1 - December 31, 2018	Year 2019	Year 2020	Year 2021
Oil Positions:				
Fixed-Price Swaps (West Texas Intermediate):				
Notional Volume (Bbls)	654,700	1,858,200	1,393,800	—
Fixed Price ($/Bbl)	$ 46.60	$ 48.50	$ 49.53	$ —
Collars:				
Notional Volume (Bbls)	—	575,730	659,340	112,036
Floor Price ($/Bbl)	$ —	$ 43.81	$ 44.17	$ 47.50
Ceiling Price ($/Bbl)	$ —	$ 54.04	$ 55.00	$ 56.05

	October 1 - December 31, 2018	Year 2019
NGLs Positions:		
Fixed-Price Swaps:		
Mont Belvieu Ethane		
Notional Volume (Gallons)	2,318,400	5,177,529
Fixed Price ($/Gallon)	$ 0.28	$ 0.34
Mont Belvieu Propane		
Notional Volume (Gallons)	5,796,000	12,402,427
Fixed Price ($/Gallon)	$ 0.53	$ 0.80
Mont Belvieu N. Butane		
Notional Volume (Gallons)	1,932,000	4,572,440
Fixed Price ($/Gallon)	$ 0.65	$ 0.93
Mont Belvieu Isobutane		
Notional Volume (Gallons)	1,545,600	3,686,779
Fixed Price ($/Gallon)	$ 0.65	$ 0.93
Mont Belvieu N. Gasoline		
Notional Volume (Gallons)	2,704,800	6,777,667
Fixed Price ($/Gallon)	$ 0.99	$ 1.37

As of September 30, 2018, the Company had the following open basis swap contracts:

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	October 1 - December 31, 2018	Year 2019
Gas Positions:		
Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential		
Notional Volume (MMBtu)	6,915,000	5,400,000
Weighted-basis differential ($/MMBtu)	$ (0.57)	$ (0.53)
Oil Positions:		
WTI Midland and WTI Cushing Basis Differential		
Notional Volume (Bbls)	—	456,250
Fixed Price ($/Bbl)	$ —	$ (5.78)

Interest Rate Risks

At September 30, 2018, we had debt outstanding of $870.1 million. The amount outstanding under our Successor Credit Facility and Successor Term Loan at September 30, 2018 was approximately $785.8 million and is subject to interest at floating rates based on LIBOR. If the debt remains the same, a 10% increase in LIBOR would result in an estimated $1.7 million increase in annual interest expense.

Counterparty Risk

At September 30, 2018, based upon all of our open derivative contracts shown above and their respective mark to market values, we had the following current and long-term derivative liabilities shown by counterparty with their current Standard & Poor's financial strength rating in parentheses (in thousands):

	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities	Total Amount Owed To Counterparty at September 30, 2018
ABN AMRO (A)	$ —	$ —	$ (29,012)	$ (6,788)	$ (35,800)
Capital One (BBB+)	—	—	(7,288)	(12,021)	(19,309)
Citibank (A+)	—	—	(13,292)	(7,310)	(20,602)
Huntington Bank (A-)	—	—	(19,502)	(14,531)	(34,033)
ING Financial Markets (A+)	87	—	—	(159)	(72)
JP Morgan (A-)	—	1,696	(350)	—	1,346
Shell Trading Risk Management (A)	—	—	(651)	(63)	(714)
Total	$ 87	$ 1,696	$ (70,095)	$ (40,872)	$ (109,184)

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with our counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each financial transaction between the counterparty and us separately, the master netting agreement enables the counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (i) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (ii) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) promulgated under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of September 30, 2018 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the third quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Litigation Relating to Vanguard's 2015 merger with LRR Energy, L.P.

In June and July 2015, purported unitholders of LRR Energy, L.P. ("LRE") filed four lawsuits challenging Vanguard's 2015 merger with LRE (the "LRE Merger"). These lawsuits were styled (a) Barry Miller v. LRR Energy, L.P. et al., Case No. 11087-VCG, in the Court of Chancery of the State of Delaware; (b) Christopher Tiberio v. Eric Mullins et al., Cause No. 2015-39864, in the District Court of Harris County, Texas, 334th Judicial District; (c) Eddie Hammond v. Eric Mullins et al., Cause No. 2015-40154, in the District Court of Harris County, Texas, 295th Judicial District; and (d) Ronald Krieger v. LRR Energy, L.P. et al., Civil Action No. 4:15-cv-2017, in the United States District Court for the Southern District of Texas, Houston Division. These lawsuits have been voluntarily dismissed or nonsuited.

On August 18, 2015, another purported LRE unitholder (the "LRE Plaintiff") filed a putative class action lawsuit in connection with the LRE Merger. This lawsuit is styled Robert Hurwitz v. Eric Mullins et al., Civil Action No. 1:15-cv-00711-MAK, in the United States District Court for the District of Delaware (the "LRE Lawsuit"). On June 22, 2016, the LRE Plaintiff filed his Amended Class Action Complaint (the "Amended LRE Complaint") against LRE, the members of the board of directors of the general partner of LRE, Vanguard, Lighthouse Merger Sub, LLC, and the members of Vanguard's board of directors (the "LRE Lawsuit Defendants").

In the Amended LRE Complaint, the LRE Plaintiff alleges multiple causes of action under the Securities Act and Exchange Act related to the registration statement and proxy statement filed with the SEC in connection with the LRE Merger (the "LRE Proxy"). In general, the LRE Plaintiff alleges that the LRE Proxy failed, among other things, to disclose allegedly material details concerning Vanguard's (x) debt obligations and (y) ability to maintain distributions to unitholders. Based on these allegations, the LRE Plaintiff sought, among other relief, to rescind the LRE Merger, and an award of damages, attorneys' fees, and costs.

On January 2, 2018, the court in the LRE Lawsuit certified a class of plaintiffs that includes all persons or entities holding LRE common units as of August 28, 2015, through the close of the LRE Merger on October 5, 2015, but excluding the LRE Lawsuit Defendants and certain related persons and entities (the "LRE Class"). The window for potential members of the LRE Class to request exclusion from the LRE Class closed on May 29, 2018, with 22 LRE unitholders timely requesting exclusion.

On June 27, 2018, the LRE Lawsuit Defendants and the LRE Plaintiff, on his own behalf and on behalf of the LRE Class, entered into a stipulation of settlement (the "Stipulation"). As amended on July 11, 2018, and on July 25, 2018, the Stipulation provides that the LRE Class will settle and release all claims against the LRE Lawsuit Defendants relating to the LRE Merger, in exchange for an aggregate settlement payment of $8.0 million. Of that settlement amount, Vanguard will contribute $0.7 million, with the remainder to be paid by the insurers of the LRE Lawsuit Defendants. The LRE Lawsuit Defendants continue to deny all allegations of liability or wrongdoing.

On July 18, 2018, the court held a hearing to consider whether to preliminarily approve the proposed settlement. In response to matters raised at that hearing, on July 25, 2018, the LRE Lawsuit Defendants and the LRE Plaintiff amended the Stipulation and submitted to the court a revised notice of proposed settlement, proof of claim and release form, and summary notice of proposed settlement. On July 26, 2018, the court entered an order preliminarily approving the settlement as set forth in the amended Stipulation.

The court has scheduled a hearing to consider final approval of the settlement on December 14, 2018. At that hearing, the court will determine, among other things, whether the proposed settlement is fair and reasonable to the LRE Class and should be approved, thereby forever barring the LRE Class (other than potential members excluded therefrom) from asserting any of the released claims against the LRE Lawsuit Defendants.

We are also defendants in certain legal proceedings arising in the normal course of our business. Management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company's condensed consolidated financial position, results of operations or cash flow, although the ultimate outcome and impact of such legal proceedings on the Company cannot be predicted with certainty. Furthermore, our insurance may not be adequate to cover all liabilities that may arise out of claims brought against us. If one or more negative outcomes were to occur relative to these matters, the aggregate impact to our financial position, results of operations or cash flow could be material.

In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under applicable environmental laws, that could have a material adverse effect on the Company's condensed consolidated financial position, results of operations or cash flow.

Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed in this Quarterly Report or our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations. For a detailed discussion of the risk factors that should be understood by any investor contemplating investment in our securities, please refer to Part I-Item 1A-Risk Factors in our 2017 Annual Report. There have been no material changes to the risk factors set forth in our 2017 Annual Report, except for the following:

We may not be able to comply with covenants in our debt instruments, and such non-compliance could result in the acceleration of such indebtedness
At September 30, 2018, we were in compliance with all of our debt covenants. Given, in part, the current environment for commodity prices and basis differentials, we updated our internal projections to take such updates into account, and, as a result of these updated projections, we now expect that we may not be in compliance with our ratio of consolidated first lien debt to EBITDA covenant as defined within the Second Amendment to the Successor Credit Facility in certain future periods, beginning with the December 2018 reporting period. In light of these updates, we have taken a number of steps to mitigate a potential default, including (i) discussions with certain banks in our Successor Credit Facility to amend our ratio of consolidated first lien debt to EBITDA covenant, (ii) continue to pursue efforts to divest certain oil and natural gas properties to use proceeds to reduce first lien leverage and (iii) investigating refinancing alternatives to replace the Successor Credit Facility. To the extent we breach the consolidated first lien debt to EBITDA covenant as defined within the Second Amendment to the Successor Credit Facility, we would be in default and the lenders would be able to accelerate the maturity of that indebtedness (which could result in an acceleration of our Senior Notes due 2024) and exercise other rights and remedies, all of which could adversely affect our operations and our ability to satisfy our obligations as they come due. These conditions raise substantial doubt about our ability to continue as a going concern within one year after the date that these financial statements are issued. No assurances can be made that we will be able to consummate such mitigation plans.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Each exhibit identified below is filed as a part of this Report.

Exhibit Number	Description of Exhibit
2.1	Modified Second Amended Joint Plan of Reorganization under Chapter 11 of Bankruptcy Code of Vanguard Natural Resources, LLC (incorporated by reference to Exhibit 2.1 to our Predecessor's Current Report on Form 8-K filed July 19, 2017)
3.1	Amended and Restated Certificate of Incorporation of Vanguard Natural Resources, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K15D5 filed August 2, 2017)
3.2	Amended and Restated Bylaws of Vanguard Natural Resources, Inc. (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K15D5 filed August 2, 2017)
3.3	Certificate of Amendment as filed with the Delaware Secretary of State (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed September 29, 2017)
4.1	Amended and Restated Indenture, dated as of August 1, 2017, among Vanguard Natural Resources, Inc., the guarantors named therein and Delaware Trust Company, as trustee and collateral trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K15D5 filed August 2, 2017)
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
32.1*	Section 1350 Certification of Chief Executive Officer
32.2*	Section 1350 Certification of Chief Financial Officer

Exhibit Number	Description of Exhibit
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

*Provided herewith.

SIGNATURES

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

	VANGUARD NATURAL RESOURCES, INC. (Registrant)
Date: November 9, 2018	/s/ Ryan Midgett Ryan Midgett Chief Financial Officer (Principal Financial Officer)