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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2017

or

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

For the transition period from ______ to ______

Commission file number: 1-13283

PENN VIRGINIA CORPORATION
(Exact name of registrant as specified in its charter)

Virginia	**23-1184320**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

14701 ST. MARY'S LANE, SUITE 275
HOUSTON, TX 77079
(Address of principal executive offices) (Zip Code)
(713) 722-6500
(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer	☐		Accelerated filer	☐
Non-accelerated filer	☐	(Do not check if a smaller reporting company)	Smaller reporting company	☒
			Emerging growth company	☐

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

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

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

As of August 4, 2017, 14,992,018 shares of common stock of the registrant were outstanding.

PENN VIRGINIA CORPORATION
QUARTERLY REPORT ON FORM 10-Q

For the Quarterly Period Ended June 30, 2017

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Part I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS – unaudited
(in thousands, except per share data)

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Revenues				
Crude oil	$ 32,351	$ 32,019	$ 62,424	$ 57,985
Natural gas liquids	2,043	2,431	4,345	4,384
Natural gas	1,880	1,917	4,223	4,319
(Loss) gain on sales of assets, net	(134)	910	(69)	757
Other, net	142	(125)	345	204
Total revenues	36,282	37,152	71,268	67,649
Operating expenses				
Lease operating	5,370	5,225	10,286	11,417
Gathering, processing and transportation	2,555	4,650	5,106	8,468
Production and ad valorem taxes	2,119	2,163	4,098	2,916
General and administrative	3,721	14,948	7,848	32,050
Exploration	—	4,320	—	5,647
Depreciation, depletion and amortization	11,076	11,746	20,886	25,558
Total operating expenses	24,841	43,052	48,224	86,056
Operating income (loss)	11,441	(5,900)	23,044	(18,407)
Other income (expense)				
Interest expense	(1,274)	(32,221)	(1,812)	(56,655)
Derivatives	11,061	(21,759)	28,077	(17,267)
Other, net	101	(6)	101	(1,030)
Reorganization items, net	—	(7,380)	—	(7,380)
Income (loss) before income taxes	21,329	(67,266)	49,410	(100,739)
Income tax benefit (expense)	—	—	—	—
Net income (loss)	21,329	(67,266)	49,410	(100,739)
Preferred stock dividends	—	(2,820)	—	(5,972)
Net income (loss) attributable to common shareholders	$ 21,329	$ (70,086)	$ 49,410	$ (106,711)
Net income (loss) per share:				
Basic	$ 1.42	$ (0.79)	$ 3.30	$ (1.22)
Diluted	$ 1.42	$ (0.79)	$ 3.27	$ (1.22)
Weighted average shares outstanding – basic	14,992	89,051	14,992	87,496
Weighted average shares outstanding – diluted	15,050	89,051	15,097	87,496

See accompanying notes to condensed consolidated financial statements.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME – unaudited
(in thousands)

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Net income (loss)	$ 21,329	$ (67,266)	$ 49,410	$ (100,739)
Other comprehensive loss:				
Change in pension and postretirement obligations, net of tax $0 and $0 in 2016	—	(11)	—	(38)
	—	(11)	—	(38)
Comprehensive income (loss)	$ 21,329	$ (67,277)	$ 49,410	$ (100,777)

See accompanying notes to condensed consolidated financial statements.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS – unaudited
(in thousands, except share data)

	June 30, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$ 10,105	$ 6,761
Accounts receivable, net of allowance for doubtful accounts	42,807	29,095
Derivative assets	2,672	—
Other current assets	3,100	3,028
Total current assets	58,684	38,884
Property and equipment, net (full cost method)	272,461	247,473
Derivative assets	584	—
Other assets	5,423	5,329
Total assets	$ 337,152	$ 291,686
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 59,263	$ 49,697
Derivative liabilities	—	12,932
Total current liabilities	59,263	62,629
Other liabilities	4,103	4,072
Derivative liabilities	90	14,437
Long-term debt	37,000	25,000
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock of $0.01 par value – 5,000,000 shares authorized; none issued	—	—
Common stock of $0.01 par value – 45,000,000 shares authorized; 14,992,018 shares issued as of June 30, 2017 and December 31, 2016	150	150
Paid-in capital	192,359	190,621
Retained earnings (accumulated deficit)	44,114	(5,296)
Accumulated other comprehensive income	73	73
Total shareholders' equity	236,696	185,548
Total liabilities and shareholders' equity	$ 337,152	$ 291,686

See accompanying notes to condensed consolidated financial statements.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – unaudited
(in thousands)

	Successor	Predecessor
	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities		
Net income (loss)	$ 49,410	$ (100,739)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	20,886	25,558
Accretion of firm transportation obligation	—	317
Derivative contracts:		
Net (gains) losses	(28,077)	17,267
Cash settlements, net	(2,458)	46,952
Loss (gain) on sales of assets, net	69	(757)
Non-cash exploration expense	—	1,713
Non-cash interest expense	988	22,189
Share-based compensation (equity-classified)	1,694	1,364
Other, net	38	(13)
Changes in operating assets and liabilities, net	(6,533)	31,922
Net cash provided by operating activities	36,017	45,773
Cash flows from investing activities		
Capital expenditures	(43,583)	(14,575)
Proceeds from sales of assets, net	—	126
Other, net	—	1,186
Net cash used in investing activities	(43,583)	(13,263)
Cash flows from financing activities		
Proceeds from credit facility borrowings	14,000	—
Repayment of credit facility borrowings	(2,000)	(5,468)
Debt issuance costs paid	(1,090)	—
Proceeds received from rights offering, net	55	—
Other, net	(55)	—
Net cash provided by (used in) financing activities	10,910	(5,468)
Net increase in cash and cash equivalents	3,344	27,042
Cash and cash equivalents – beginning of period	6,761	11,955
Cash and cash equivalents – end of period	$ 10,105	$ 38,997
Supplemental disclosures:		
Cash paid for:		
Interest, net of amounts capitalized	$ 795	$ 2,765
Income taxes, net of (refunds)	$ —	$ (35)
Reorganization items, net	$ 901	$ 174
Non-cash investing and financing activities:		
Changes in accrued liabilities related to capital expenditures	$ 2,322	$ (10,555)
Derivatives settled to reduce outstanding debt	$ —	$ 51,979

See accompanying notes to condensed consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation (together with its consolidated subsidiaries, unless the context otherwise requires, "Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company engaged in the onshore exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash. In August 2016, we terminated our remaining operations in the Marcellus Shale in Pennsylvania and recently completed remediation activities at the sites of our former wells in that region. We are currently awaiting releases from state environmental authorities to finalize our exit activities.

2. Basis of Presentation

Our unaudited Condensed Consolidated Financial Statements include the accounts of Penn Virginia and all of our subsidiaries. Intercompany balances and transactions have been eliminated. Our Condensed Consolidated Financial Statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP"). Preparation of these statements involves the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation of our Condensed Consolidated Financial Statements have been included. Our Condensed Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements and Notes included in our Annual Report on Form 10-K for the year ended December 31, 2016. Operating results for the six months ended June 30, 2017, are not necessarily indicative of the results that may be expected for the year ending December 31, 2017.

Comparability of Financial Statements to Prior Periods

We adopted and began applying the relevant guidance provided in GAAP with respect to the accounting and financial statement disclosures for entities that have emerged from bankruptcy proceedings ("Fresh Start Accounting") on September 12, 2016. Accordingly, our Condensed Consolidated Financial Statements and Notes after September 12, 2016, are not comparable to the Condensed Consolidated Financial Statements and Notes through that date. To facilitate our financial statement presentations, we refer to the reorganized company in these Condensed Consolidated Financial Statements and Notes as the "Successor," which is effectively a new reporting entity for financial reporting purposes, for periods subsequent to September 12, 2016, and the "Predecessor" for periods prior to September 13, 2016. In connection with our reorganization, we experienced a change in control as the outstanding common and preferred shares of the Predecessor were canceled and substantially all of the Successor's new common stock was issued to the Predecessor's creditors.

Furthermore, our Condensed Consolidated Financial Statements and Notes have been presented with a "black line" division to delineate, where applicable, the lack of comparability between the Predecessor and Successor. In addition, we adopted the full cost method of accounting for our oil and gas properties effective with our adoption of Fresh Start Accounting. Accordingly, our results of operations, financial position and cash flows for the Successor periods will be substantially different from our historic trends.

We have recasted amounts for equity-classified share-based compensation recognized as a component of "General and administrative" expenses from the amounts originally reported for the three and six months ended June 30, 2016 to correct for an immaterial error identified by management and disclosed in our Quarterly Report on Form 10-Q for the period ended September 30, 2016. Previously reported expenses associated with this matter, as well as our operating losses and net losses, were increased by $5.3 million for each of the three and six-month periods ended June 30, 2016. Our net loss per basic and diluted share increased by $0.06 for each of the three and six-month periods ended June 30, 2016.

Going Concern Presumption

Our unaudited Condensed Consolidated Financial Statements for the Successor periods have been prepared on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities and other commitments in the normal course of business.

Subsequent Events

In July 2017, we entered into a definitive agreement to acquire Eagle Ford properties located primarily in Lavaca County, Texas for $205 million in cash, subject to customary purchase price adjustments, from Devon Energy Corporation. The acquisition has an effective date of March 1, 2017 and is expected to close in September 2017, subject to customary closing conditions. With the exception of the pending acquisition, management has evaluated all of our activities through the issuance date of our Condensed Consolidated Financial Statements and has concluded that no subsequent events have occurred that would require recognition in our Condensed Consolidated Financial Statements or disclosure in the Notes thereto.

Recently Issued Accounting Pronouncements

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017–07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* ("ASU 2017–07") which provides guidance to improve the reporting of net benefit cost in financial statements. The guidance requires employers to disaggregate the service cost component from the other components of net benefit cost. The service cost component of net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period, except for amounts capitalized. All other components of net benefit cost shall be presented outside of a subtotal for income from operations. The line item used to present the components other than the service cost shall be disclosed if the other components are not presented in a separate line item or items. ASU 2017–07 is effective January 1, 2018 and is required to be applied retrospectively. ASU 2017–07 will be applicable to our legacy retiree benefit plans which cover a limited population of former employees. There is no service cost associated with these plans as they are not applicable to current employees, but rather "interest and other costs" associated with the legacy obligations. Upon the adoption of ASU 2017–07, the entirety of the expense associated with these plans will be presented as a component of the "Other income (expense)" caption in our Condensed Consolidated Statement of Operations. These costs are currently recognized as a component of "General and administrative" expenses. The total cost associated with these plans is generally less than $0.1 million on an annual basis and is therefore not material. We will adopt ASU 2017–07 in January 2018.

In June 2016, the FASB issued ASU 2016–13, *Measurement of Credit Losses on Financial Instruments* ("ASU 2016–13"), which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold, (an "incurred loss" model), ASU 2016–13 mandates an "expected loss" model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and reasonable supported forecasts and (iv) has no recognition threshold. ASU 2016–13 will have applicability to our accounts receivable portfolio, particularly those receivables attributable to our joint interest partners. At this time, we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures; however, we are currently in the early stages of evaluating the requirements and the period for which we will adopt the standard.

In February 2016, the FASB issued ASU 2016–02, *Leases* ("ASU 2016–02"), which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than twelve months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–02 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASU 2016–02 is January 1, 2019, with early adoption permitted. We believe that ASU 2016–02 will likely be applicable to our oil and natural gas gathering commitment arrangements as described in Note 12, our existing leases for office facilities and certain office equipment and potentially to certain drilling rig and completion contracts with terms in excess of twelve months to the extent we may have such contracts in the future. Our oil and natural gas gathering arrangements are fairly complex and involve multiple elements that could be construed as leases. Accordingly, we are continuing to evaluate the effect that ASU 2016–02 will have on our Consolidated Financial Statements and related disclosures as well as the period for which we will adopt the standard, however, at this time, we believe that we will likely adopt ASU 2016–02 in 2019.

In May 2014, the FASB issued ASU 2014–09, *Revenues from Contracts with Customers* ("ASU 2014–09"), which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. While traditional commodity sales transactions, property conveyances and joint interest arrangements in the oil and gas industry are not expected to be significantly impacted by ASU 2014–09, natural gas imbalances and other non-product revenues, including our ancillary marketing, gathering and transportation and water disposal revenues could be affected. Accordingly, we are continuing to evaluate the effect that ASU 2014–09 will have on our Consolidated Financial Statements and related disclosures, with a more focused analysis on these other revenue sources, which we do not believe are significant. We are also continuing to monitor developments regarding ASU 2014–09 that are unique to our industry. We will adopt ASU 2014–09 in January 2018 using the cumulative effect transition method.

3. Bankruptcy Proceedings and Emergence

On May 12, 2016 (the "Petition Date"), we and eight of our subsidiaries filed voluntary petitions (*In re Penn Virginia Corporation, et al., Case No. 16-32395*) seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Virginia (the "Bankruptcy Court").

On August 11, 2016 (the "Confirmation Date"), the Bankruptcy Court confirmed our Second Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and its Debtor Affiliates (the "Plan"), and we subsequently emerged from bankruptcy on September 12, 2016 (the "Effective Date").

While our emergence from bankruptcy is effectively complete, certain administrative and claims resolution activities will continue under the authority of the Bankruptcy Court until complete. As of August 4, 2017, certain claims were still in the process of resolution. While most of these matters are unsecured claims for which shares of Successor common stock have been allocated, certain of these matters must be settled with cash payments. As of June 30, 2017, we had $3.9 million reserved for outstanding claims to be potentially settled in cash. This reserve is included as a component of "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheet.

4. Accounts Receivable and Major Customers

The following table summarizes our accounts receivable by type as of the dates presented:

	June 30, 2017	December 31, 2016
Customers	$ 22,920	$ 20,489
Joint interest partners	21,598	7,238
Other [1]	670	3,789
	45,188	31,516
Less: Allowance for doubtful accounts	(2,381)	(2,421)
	$ 42,807	$ 29,095

[1] Includes amounts owed to us from joint venture partners for acquisitions in prior periods, severance tax refunds approved by state taxing authorities to be returned to us and other miscellaneous non-operating items.

For the six months ended June 30, 2017, one customer accounted for $64.6 million, or approximately 91%, of our consolidated product revenues. As of June 30, 2017, $19.2 million, or approximately 84%, of our consolidated accounts receivable from customers was related to this customer. For the six months ended June 30, 2016, three customers accounted for $62.2 million, or approximately 93%, of our consolidated product revenues. The revenues generated from these customers during the six months ended June 30, 2016 were $32.1 million, $16.2 million and $13.9 million, or approximately 48%, 24% and 21% of the consolidated total, respectively. As of December 31, 2016, $16.7 million, or approximately 81%, of our consolidated accounts receivable from customers was related to these customers. No significant uncertainties exist related to the collectability of amounts owed to us by any of these customers.

5. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to crude oil and natural gas price volatility. Our derivative instruments are not formally designated as hedges in the context of GAAP.

We typically utilize collars and swaps, which are placed with financial institutions that we believe are acceptable credit risks, to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

The counterparty to a collar or swap contract is required to make a payment to us if the settlement price for any settlement period is below the floor or swap price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling or swap price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for West Texas Intermediate crude oil and NYMEX Henry Hub gas and closing prices as of the end of the reporting period. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position and our own credit risk if the derivative is in a liability position.

We terminated all of our pre-petition derivative contracts from March 2016 through May 2016 for $63.0 million and reduced amounts outstanding under the pre-petition credit agreement (the "RBL") by $52.0 million. In connection with these transactions, the counterparties to the derivative contracts, which were also affiliates of lenders under the RBL, transferred the cash proceeds that were used for RBL repayments directly to the administrative agent under the RBL. Accordingly, all of these RBL repayments have been presented as non-cash financing activities on our Condensed Consolidated Statement of Cash Flows for the six months ended June 30, 2016.

In May 2016, we entered into a series of new commodity derivative contracts. Accordingly, we hedged a substantial portion of our future crude oil production through the end of 2019 at a weighted-average price of approximately $49.07 per barrel. We are currently unhedged with respect to NGL and natural gas production.

The following table sets forth our commodity derivative positions as of June 30, 2017:

	Instrument	Average Volume Per Day	Weighted Average Swap Price	Fair Value: Asset	Fair Value: Liability
Crude Oil:		(barrels)	($/barrel)		
Third quarter 2017	Swaps	4,408	$ 48.59	$ 903,636	$ —
Fourth quarter 2017	Swaps	4,408	$ 48.59	591,129	—
First quarter 2018	Swaps	3,476	$ 49.10	419,761	—
Second quarter 2018	Swaps	3,476	$ 49.10	299,826	—
Third quarter 2018	Swaps	3,476	$ 49.10	193,534	—
Fourth quarter 2018	Swaps	3,476	$ 49.10	82,328	—
First quarter 2019	Swaps	2,916	$ 49.75	160,594	—
Second quarter 2019	Swaps	2,916	$ 49.75	88,824	—
Third quarter 2019	Swaps	2,916	$ 49.75	24,775	—
Fourth quarter 2019	Swaps	2,916	$ 49.75	—	56,550
Settlements to be received in subsequent period				457,245	

Financial Statement Impact of Derivatives

The impact of our derivative activities on income is included in "Derivatives" in our Condensed Consolidated Statements of Operations. The following table summarizes the effects of our derivative activities for the periods presented:

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Derivative gains (losses)	$ 11,061	$ (21,759)	$ 28,077	$ (17,267)

The effects of derivative gains and (losses) and cash settlements (except for those cash settlements attributable to the aforementioned termination transactions) are reported as adjustments to reconcile net income (loss) to net cash provided by operating activities. These items are recorded in the "Derivative contracts" section of our Condensed Consolidated Statements of Cash Flows under "Net (gains) losses" and "Cash settlements, net."

The following table summarizes the fair values of our derivative instruments, as well as the locations of these instruments on our Condensed Consolidated Balance Sheets as of the dates presented:

		Fair Values as of			
		June 30, 2017		December 31, 2016	
		Derivative	Derivative	Derivative	Derivative
Type	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ 2,672	$ —	$ —	$ 12,932
Commodity contracts	Derivative assets/liabilities – noncurrent	584	90	—	14,437
		$ 3,256	$ 90	$ —	$ 27,369

As of June 30, 2017, we reported commodity derivative asset of $3.2 million. The contracts associated with this position are with two counterparties, both of which are investment grade financial institutions. This concentration may impact our overall credit risk in that these counterparties may be similarly affected by changes in economic or other conditions. We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

6. Property and Equipment

The following table summarizes our property and equipment as of the dates presented:

	June 30, 2017	December 31, 2016
Oil and gas properties:		
Proved	$ 297,390	$ 251,083
Unproved	4,122	4,719
Total oil and gas properties	301,512	255,802
Other property and equipment	3,696	3,575
Total properties and equipment	305,208	259,377
Accumulated depreciation, depletion and amortization	(32,747)	(11,904)
	$ 272,461	$ 247,473

Unproved property costs of $4.1 million and $4.7 million have been excluded from amortization as of June 30, 2017 and December 31, 2016, respectively. We transferred $2.0 million of undeveloped leasehold costs associated with acreage unlikely to be drilled or associated with proved undeveloped reserves, including capitalized interest, from unproved properties to the full cost pool during the six months ended June 30, 2017. We capitalized internal costs of $1.1 million and interest of $0.1 million during the six months ended June 30, 2017 in accordance with our accounting policies. Average depreciation, depletion and amortization per barrel of oil equivalent of proved oil and gas properties was $11.74 and $10.02 for the six months ended June 30, 2017 and 2016, respectively.

7. Long-Term Debt

Credit Facility

On the Effective Date upon our emergence from bankruptcy, we entered into our credit agreement (the "Credit Facility"). The Credit Facility currently provides for a $200 million revolving commitment and borrowing base and a $5 million sublimit for the issuance of letters of credit. In June 2017, the borrowing base was redetermined from $128 million to $200 million pursuant to an amendment to the Credit Facility (the "Amendment"). In connection with the Amendment, we paid and capitalized issue costs of $1.1 million and wrote-off $0.6 million of previously capitalized issue costs due to a change in the composition of financial institutions comprising the Credit Facility bank group. The availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base. The borrowing base under the Credit Facility is generally redetermined semi-annually in April and October of each year. Additionally, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us to pay expenses associated with our bankruptcy proceedings and for general corporate purposes including working capital. The Credit Facility matures in September 2020. We had outstanding borrowings of $37 million and $25 million under the Credit Facility as of June 30, 2017 and December 31, 2016, respectively. We also had $0.8 million in letters of credit outstanding as of June 30, 2017 and December 31, 2016.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate ("LIBOR") plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on LIBOR borrowings is payable every one, three or six months, at our election, and is computed on the basis of a year of 360 days. As of June 30, 2017, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 4.3289%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by us and all of our subsidiaries (the "Guarantor Subsidiaries"). The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. The parent company has no material independent assets or operations. There are no significant restrictions on the ability of the parent company or any of the Guarantor Subsidiaries to obtain funds through dividends, advances or loans. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our assets.

The Credit Facility requires us to maintain (1) a minimum interest coverage ratio (adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses as defined in the Credit Facility ("EBITDAX") to adjusted interest expense), measured as of the last day of each fiscal quarter, of 3.00 to 1.00, (2) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00, and (3) a maximum leverage ratio (consolidated indebtedness to EBITDAX), measured as of the last day of each fiscal quarter, initially of 4.00 to 1.00, decreasing on December 31, 2017 to 3.75 to 1.00 and on March 31, 2018 and thereafter to 3.50 to 1.00.

The Credit Facility also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

The Credit Facility contains customary events of default and remedies for credit facilities of this nature. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility.

As of June 30, 2017, we were in compliance with all of these covenants.

8. Income Taxes

We recognized a federal and state income tax expense for the six months ended June 30, 2017 at the blended rate of 35.52%; however, the federal and state tax expense was fully offset by an adjustment to the valuation allowance against our net deferred tax assets. We recognized a federal income tax benefit for the six months ended June 30, 2016 at the statutory rate of 35% which was fully offset by a valuation allowance against our net deferred tax assets. We considered both the positive and negative evidence in determining that it was more likely than not that some portion or all of our deferred tax assets will not be realized, primarily as a result of cumulative losses. We received a state income tax refund of less than $0.1 million during the six months ended June 30, 2016.

We have evaluated the impact of the reorganization, including the change in control, resulting from our emergence from bankruptcy. From an income tax perspective, the most significant impact is attributable to our carryover tax attributes associated with our net operating losses ("NOLs"). We believe that the Successor will be able to fully absorb the cancellation of debt income realized by the Predecessor in connection with the reorganization with its adjusted NOL carryovers. The amount of the remaining NOL carryovers and the tax basis of our properties will be limited under Section 382 of the Internal Revenue Code due to the change in control that occurred upon our emergence from bankruptcy on the Effective Date. As the tax basis of our assets, primarily our oil and gas properties, is in excess of the carrying value, as adjusted in the Fresh Start Accounting process, the Successor is in a net deferred tax asset position. We have determined that it is more likely than not that we will not realize future income tax benefits from the additional tax basis and our remaining NOL carryovers. Accordingly, we have provided for a full valuation allowance of the underlying deferred tax assets.

9. Exit Activities

Prior to the Effective Date, the Predecessor committed to a number of actions, or exit activities, the most significant of which are described below.

Reductions in Force

In connection with efforts to reduce our administrative costs, we took certain actions to reduce our total employee headcount. In 2016, we reduced our total employee headcount by 53 employees including 28 of whom were terminated in the six months ended June 30, 2016. We incurred charges of $1.1 million in connection with this action and paid a total of $0.7 million in severance and termination benefits during the six months ended June 30, 2016. We recognized an immaterial credit adjustment to the remaining obligation of less than $0.1 million during the period ended June 30, 2017. There were no payments under these obligations during the six months ended June 30, 2017.

The costs associated with these reduction-in-force actions are included as a component of our "General and administrative" expenses in our Condensed Consolidated Statements of Operations. The related obligation is included in "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheet.

Drilling Rig Termination

In connection with the suspension of our 2016 drilling program in the Eagle Ford, we terminated a drilling rig contract and incurred $1.3 million in early termination charges during the six months ended June 30, 2016. As this obligation represented a pre-petition liability of the Predecessor, it was discharged in connection with our emergence from bankruptcy. The vendor recovered a portion of the amount in the form of Successor common stock.

Firm Transportation Obligation

We had a contractual obligation for certain firm transportation capacity in the Appalachian region that was scheduled to expire in 2022 and, as a result of the sale of our natural gas assets in this region in 2012, we no longer had production available to satisfy this commitment. We originally recognized a liability in 2012 representing this obligation for the estimated discounted future net cash outflows over the remaining term of the contract. The accretion of the obligation through the Petition Date, net of any recoveries from periodic sales of our contractual capacity, was charged as an offset to Other revenue. During the six months ended June 30, 2016, we paid a total of $1.1 million and recognized accretion expense of $0.3 million attributable to the underlying obligation. In connection with our emergence from bankruptcy, we rejected the underlying contract.

10. Additional Balance Sheet Detail

The following table summarizes components of selected balance sheet accounts as of the dates presented:

	June 30, 2017	December 31, 2016
Other current assets:		
Tubular inventory and well materials	$ 2,100	$ 2,125
Prepaid expenses	1,000	903
	$ 3,100	$ 3,028
Other assets:		
Deferred issuance costs of the Credit Facility	$ 2,887	$ 2,785
Other	2,536	2,544
	$ 5,423	$ 5,329
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 10,166	$ 9,825
Drilling costs	4,802	2,479
Royalties and revenue – related	33,231	26,116
Compensation – related	1,739	2,557
Interest	84	55
Reserve for bankruptcy claims	3,922	3,922
Other	5,319	4,743
	$ 59,263	$ 49,697
Other liabilities:		
Asset retirement obligations (“AROs”)	$ 2,506	$ 2,459
Defined benefit pension obligations	972	1,025
Postretirement health care benefit obligations	525	488
Other	100	100
	$ 4,103	$ 4,072

11. Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive upon the sale of an asset or that we would expect to pay to transfer a liability in an orderly transaction with market participants at the measurement date.

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and our Credit Facility borrowings. As of June 30, 2017, the carrying values of all of these financial instruments approximated fair value.

Recurring Fair Value Measurements

Certain financial assets and liabilities are measured at fair value on a recurring basis on our Condensed Consolidated Balance Sheets. The following tables summarize the valuation of those assets and liabilities as of the dates presented:

	June 30, 2017			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$ 2,672	$ —	$ 2,672	$ —
Commodity derivative assets – noncurrent	584	—	584	—
Liabilities:				
Commodity derivative liabilities – current	$ —	$ —	$ —	$ —
Commodity derivative liabilities – noncurrent	(90)	—	(90)	—

	December 31, 2016			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Liabilities:				
Commodity derivative liabilities – current	$ (12,932)	$ —	$ (12,932)	$ —
Commodity derivative liabilities – noncurrent	(14,437)	—	(14,437)	—

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one level of the fair value hierarchy to another level. In such instances, the transfer is deemed to have occurred at the beginning of the quarterly period in which the event or change in circumstances that caused the transfer occurred. There were no transfers during the six months ended June 30, 2017 and 2016.

We used the following methods and assumptions to estimate fair values for the financial assets and liabilities described below:

- *Commodity derivatives*: We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for West Texas Intermediate crude oil and NYMEX Henry Hub gas closing prices as of the end of the reporting periods. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a level 2 input.

Non-Recurring Fair Value Measurements

The most significant non-recurring fair value measurements utilized in the preparation of our Condensed Consolidated Financial Statements are those attributable to the initial determination of AROs associated with the ongoing development of new oil and gas properties. The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial estimates as level 3 inputs.

In addition, we utilize non-recurring fair value measurements with respect to the recognition and measurement of asset impairments, particularly during our Predecessor periods during which time we applied the successful efforts method to our oil and gas properties. The factors used to determine fair value for purposes of recognizing and measuring asset impairments while we applied the successful efforts method to our oil and gas properties during our Predecessor periods included, but were not limited to, estimates of proved and risk-adjusted probable reserves, future commodity prices, indicative sales prices for properties, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs were typically not observable, we have categorized the amounts as level 3 inputs. Under the full cost method, which we have applied since the Effective Date, we apply a ceiling test determination utilizing prescribed procedures. The full cost method is substantially different from the successful efforts method which relies upon fair value measurements.

12. Commitments and Contingencies

Gathering and Intermediate Transportation Commitments

We have long-term agreements with Republic Midstream, LLC ("Republic Midstream") and Republic Midstream Marketing, LLC ("Republic Marketing" and, together with Republic Midstream, collectively, "Republic") to provide for gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production in the South Texas region as well as volume capacity support for certain downstream interstate pipeline transportation.

Republic is obligated to gather and transport our crude oil and condensate from within a dedicated area in the Eagle Ford via a gathering system and intermediate takeaway pipeline connecting to a downstream interstate pipeline operated by a third party through 2041. We have a minimum volume commitment of 8,000 gross barrels of oil per day to Republic through 2031 under the gathering agreement. Under the marketing agreement, we have a 10-year commitment to sell 8,000 barrels per day of crude oil to Republic, or any third party, utilizing Republic Marketing's capacity on a certain downstream interstate pipeline.

Excluding the potential impact of the effects of price escalation from commodity price changes, the minimum fee requirements under the Amended Agreements are as follows: $5.0 million for the remainder of 2017, $10.4 million for 2018, $11.7 million for 2019, $13.0 million for 2020 through 2025, $7.4 million for 2026, $3.8 million for 2027 through 2030 and $2.2 million for 2031.

Drilling Commitments

As of June 30, 2017, we had contractual commitments for two drilling rigs. The first rig is subject to a six-month commitment through September 2017. The second rig, which completed a seven-well commitment in July 2017, was extended for a six-month commitment that ends in January 2018. We have approximately $4.5 million of remaining obligations associated with these commitments.

Legal and Regulatory

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. As of June 30, 2017, we continue to maintain a $0.1 million reserve for a litigation matter. As of June 30, 2017, we also had AROs of approximately $2.5 million attributable to the plugging of abandoned wells.

13. Shareholders' Equity

The following tables summarize the components of our shareholders' equity and the changes therein as of and for six months ended June 30, 2017:

	December 31, 2016	Net Income	All Other Changes [1]	June 30, 2017
Common stock	$ 150	$ —	$ —	$ 150
Paid-in capital	190,621	—	1,738	192,359
Retained earnings (accumulated deficit)	(5,296)	49,410	—	44,114
Accumulated other comprehensive income	73	—	—	73
	$ 185,548	$ 49,410	$ 1,738	$ 236,696

[1] Includes equity-classified share-based compensation of $1.7 million and $0.1 million from the receipt in May 2017 of proceeds attributable to the rights offering in 2016 that had been held in escrow, net of costs to register our common stock.

14. Share-Based Compensation and Other Benefit Plans

Share-Based Compensation

We recognize share-based compensation expense related to our share-based compensation plans as a component of "General and administrative" expense in our Condensed Consolidated Statements of Operations.

In the Predecessor periods in 2016 we had outstanding equity-classified awards in the form of stock options, restricted stock units and deferred stock units. All outstanding equity-classified share-based compensation awards were canceled in connection with our emergence from bankruptcy. We reserved 749,600 shares of Successor common Stock for issuance under the Penn Virginia Corporation Management Incentive Plan for future share-based compensation awards. A total of 256,400 shares of time-vested restricted stock units ("RSUs") and 62,675 performance restricted stock units ("PRSUs") had been granted as of June 30, 2017.

The following table summarizes our share-based compensation expense (benefit) recognized for the periods presented:

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Equity-classified awards [1]	$ 848	$ 1,965	$ 1,694	$ 1,364
Liability-classified awards	—	(12)	—	(19)
	$ 848	$ 1,953	$ 1,694	$ 1,345

[1] Amounts for the 2016 periods have been recasted (see Note 2).

In the six months ended June 30, 2017, we granted 148,837 RSUs to certain employees with an average grant-date fair value of $51.50 per RSU. The RSUs are being charged to expense on a straight-line basis over five years. In January 2017, we also granted 62,675 PRSUs to members of our management. The PRSUs were issued collectively in three separate tranches with individual three-year performance periods beginning in January 2017, 2018 and 2019, respectively. Vesting of the PRSUs can range from zero to 200 percent of the original grant based on the performance of our common stock relative to an industry index. The grant date fair values of the individual tranches were $65.28 for the first performance period tranche and $61.74 for each of the second and third performance period tranches. Due to their market condition, the PRSUs are being charged to expense using graded vesting over five years. The fair value of each PRSU award was estimated on the January 26, 2017 date of grant using a Monte Carlo simulation. Expected volatilities were based on historical volatilities. A risk-free rate of interest of 1.49% was utilized which is equivalent to the yield, as of the measurement date, of the zero-coupon U.S. Treasury bill commensurate with the longest remaining performance measurement period for each tranche. We assumed no payment of dividends during the performance periods.

Other Benefit Plans

We maintain the Penn Virginia Corporation and Affiliated Companies Employees 401(k) Plan (the “401(k) Plan”), a defined contribution plan, which covers substantially all of our employees. We recognized $0.1 million and $0.2 million of expense attributable to the 401(k) Plan for the three and six months ended June 30, 2017, respectively and $0.2 million and $0.3 million of expense attributable to the 401(k) Plan for the three and six months ended June 30, 2016, respectively.

We maintain unqualified legacy defined benefit pension and defined benefit postretirement plans that cover a limited number of former employees, all of whom retired prior to 2000. The combined expense recognized with respect to these plans was less than $0.1 million for each of the three and six months ended June 30, 2017 and 2016.

15. Interest Expense

The following table summarizes the components of interest expense for the periods presented:

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Interest on borrowings and related fees [1]	$ 515	$ 11,344	$ 905	$ 34,649
Amortization of debt issuance costs [2]	800	20,920	988	22,189
Capitalized interest	(41)	(43)	(81)	(183)
	$ 1,274	$ 32,221	$ 1,812	$ 56,655

[1] Absent the bankruptcy proceedings and the corresponding suspension of the accrual of interest on unsecured debt, we would have recorded total contractual interest expense of $23.5 million and $46.9 million for the three and six months ended June 30, 2016, including $ 5.4 million and $10.9 million attributable to the 7.25% Senior Notes due 2019 (“2019 Senior Notes”) and $16.5 million and $32.9 million attributable to the 8.5% Senior Notes due 2020 (together with the 2019 Senior Notes, the “Senior Notes”).

[2] Includes a $0.6 million write-off in June 2017 attributable to a change in the composition of financial institutions comprising the Credit Facility’s bank group (see Note 7). Includes $20.5 million related to the accelerated write-off of unamortized debt issuance costs associated with the RBL and Senior Notes for the six months ended June 30, 2016.

16. Earnings (Loss) per Share

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings (loss) per share for the periods presented:

	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Net income (loss)	$ 21,329	$ (67,266)	$ 49,410	$ (100,739)
Less: Preferred stock dividends [1]	—	(2,820)	—	(5,972)
Net income (loss) attributable to common shareholders – basic and diluted	$ 21,329	$ (70,086)	$ 49,410	$ (106,711)
Weighted-average shares – basic	14,992	89,051	14,992	87,496
Effect of dilutive securities [2]	58	—	105	—
Weighted-average shares – diluted	15,050	89,051	15,097	87,496

[1] Dividends attributable to our Series A 6% Convertible Perpetual Preferred Stock and Series B 6% Convertible Perpetual Preferred Stock (together, the "Series A and B Preferred Stock") were excluded from the computation of diluted loss per share for the three and six months ended June 30, 2016 , as their assumed conversion would have been anti-dilutive.

[2] The number of dilutive securities for the three and six months ended June 30, 2017 , which is attributable to RSUs and PRSUs, was determined under the "treasury stock" method. For the six months ended June 30, 2016 , approximately 26.6 million of potentially dilutive securities, including the Series A and Series B Preferred Stock, stock options and restricted stock units, had the effect of being anti-dilutive and were excluded from the calculation of diluted loss per common share.

Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- timing, costs and unknown risks related to the pending acquisition, our ability to realize expected benefits of the pending acquisition and the risk that the acquisition is not consummated as expected;
- potential adverse effects of the completed Chapter 11, or bankruptcy, proceedings on our liquidity, results of operations, business prospects, ability to retain financing and other risks and uncertainties related to our emergence from bankruptcy;
- our ability to satisfy our short-term and long-term liquidity needs, including our inability to generate sufficient cash flows from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs;
- negative events or publicity adversely affecting our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties;
- our post-bankruptcy capital structure and the adoption of Fresh Start Accounting, including the risk that assumptions and factors used in estimating enterprise value vary significantly from the current estimates in connection with the application of fresh start accounting;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- our ability to execute our business plan in volatile and depressed commodity price environments;
- the decline in and volatility of commodity prices for oil, natural gas liquids, or NGLs, and natural gas;
- our ability to develop, explore for, acquire and replace oil and gas reserves and sustain production;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, NGLs and natural gas;
- our ability to contract for drilling rigs, frac crews, supplies and services at reasonable costs;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell our production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from estimated proved oil and gas reserves;
- drilling and operating risks;
- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- counterparty risk related to the ability of these parties to meet their future obligations;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties relating to general domestic and international economic and political conditions;
- the impact and costs associated with litigation or other legal matters; and
- other factors set forth in our periodic filings with the Securities and Exchange Commission, including the risks set forth in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management’s views only as of the date hereof. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

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

The following discussion and analysis of the financial condition and results of operations of Penn Virginia Corporation and its consolidated subsidiaries ("Penn Virginia," the "Company," "we," "us" or "our") should be read in conjunction with our Condensed Consolidated Financial Statements and Notes thereto included in Part I, Item 1, "Financial Statements." All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Also, due to the combination of different units of volumetric measure, the number of decimal places presented and rounding, certain results may not calculate explicitly from the values presented in the tables.

Overview and Executive Summary

We are an independent oil and gas company engaged in the onshore exploration, development and production of oil, natural gas liquids, or NGLs, and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale, or the Eagle Ford, in South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash. In August 2016, we terminated our remaining operations in the Marcellus Shale in Pennsylvania and recently completed remediation activities at the sites of our former wells in that region. We are currently awaiting releases from state environmental authorities to finalize our exit activities.

While crude oil prices have recovered somewhat from recent historically low levels of less than $30 per barrel, or Bbl, in February 2016 to approximately $55 per Bbl by the end of 2016, they remain depressed due to domestic and global supply and demand factors compared to the period from 2009 through 2014 when we initially began our expansion into the Eagle Ford. Similarly, the costs for drilling, completion and general oilfield products and services have declined as the industry experienced reduced demand for such products and services. While many of these costs remain at low levels, certain costs, including those for drilling and completion services, have risen as industry drilling activity continues to recover and expand. Among other factors expected to drive this increase is the consolidation of certain service providers as financially weaker vendors were forced out of the market resulting in fewer choices for upstream producers.

As discussed in Note 2 to our Condensed Consolidated Financial Statements, we adopted and began applying the relevant guidance with respect to the accounting and financial reporting for entities that have emerged from bankruptcy proceedings, or Fresh Start Accounting on September 12, 2016. Accordingly, our Condensed Consolidated Financial Statements and Notes after September 12, 2016, are not comparable to the Condensed Consolidated Financial Statements and Notes prior to that date. To facilitate the discussion and analysis of our financial condition and results of operations herein, we refer to the reorganized company as the "Successor" for periods subsequent to September 12, 2016, and the "Predecessor" for periods prior to September 13, 2016. Furthermore, our presentations herein include a "black line" division, where applicable, to delineate the lack of comparability between the Predecessor and Successor. In order to further facilitate our discussion, we have addressed the Successor and Predecessor periods discretely and have provided comparative analysis, to the extent that it is practical, where appropriate. In addition, and as referenced in Note 2 to the Condensed Consolidated Financial Statements, we have adopted the full cost method of accounting for our oil and gas properties effective with our adoption of Fresh Start Accounting. Accordingly, our results of operations, financial position and cash flows for the Successor periods will be substantially different from our historic trends.

The following summarizes our key operating and financial highlights for the three months ended June 30, 2017 with comparison to the three months ended March 31, 2017. The year-over-year highlights are addressed in further detail in the discussions for *Results of Operations* and *Financial Condition* that follow:

- Production increased approximately eight percent to 925 thousand barrels of oil equivalent, or MBOE, from 855 MBOE due primarily to the expansion of our drilling program partially offset by natural declines.
- Product revenues increased approximately five percent to $36.3 million from $34.7 million due to higher crude oil and NGL volumes partially offset by lower natural gas volumes and lower pricing for all commodity products.
- Production and lifting costs increased on an absolute basis to $7.9 million from $7.5 million, but declined on a per unit basis to $8.58 per BOE from $8.73 per BOE due primarily to the increase in production volume despite higher surface and other repair and maintenance costs.
- Production and severance taxes were relatively consistent on an absolute basis and declined to $2.29 per BOE from $2.31 per BOE on a per unit basis due to lower overall product pricing.
- General and administrative expenses declined on an absolute and per unit basis to $3.7 million and $4.03 per BOE from $4.1 million and $4.83 per BOE, respectively, due primarily to continuing efforts to manage our support cost structure and the effect of higher production volume.
- Our operating income was relatively consistent at $11.4 million for the three months ended June 30, 2017 compared to $11.6 million for the three months ended March 31, 2017.

The following table sets forth certain historical summary operating and financial statistics for the periods presented:

	Successor Three Months Ended June 30, 2017	Successor Three Months Ended March 31, 2017	Predecessor Three Months Ended June 30, 2016	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016
Total production (MBOE)	925	855	1,156	1,779	2,551
Average daily production (BOEPD)	10,159	9,495	12,706	9,829	14,014
Crude oil production (MBbl)	685	608	791	1,293	1,764
Crude oil production as a percent of total	74%	71%	68%	73%	69%
Product revenues	$ 36,274	$ 34,718	$ 36,367	$ 70,992	$ 66,688
Crude oil revenues	$ 32,351	$ 30,073	$ 32,019	$ 62,424	$ 57,985
Crude oil revenues as a percent of total	89%	87%	88%	88%	87%
Realized prices:					
Crude oil ($ per Bbl)	$ 47.25	$ 49.47	$ 40.48	$ 48.29	$ 32.87
NGLs ($ per Bbl)	$ 15.59	$ 19.34	$ 13.01	$ 17.38	$ 10.95
Natural gas ($ per Mcf)	$ 2.88	$ 3.06	$ 1.79	$ 2.98	$ 1.86
Aggregate ($ per BOE)	$ 39.24	$ 40.63	$ 31.45	$ 39.90	$ 26.15
Prices adjusted for derivatives:					
Crude oil ($ per Bbl)	$ 46.57	$ 46.19	$ 61.20	$ 46.39	$ 59.49
Aggregate ($ per BOE)	$ 38.73	$ 38.30	$ 45.63	$ 38.52	$ 44.55
Production and lifting costs ($/BOE)					
Lease operating	$ 5.81	$ 5.75	$ 4.52	$ 5.78	$ 4.48
Gathering, processing and transportation	$ 2.77	$ 2.98	$ 4.02	$ 2.87	$ 3.32
Production and ad valorem taxes ($ per BOE)	$ 2.29	$ 2.31	$ 1.87	$ 2.30	$ 1.14
General and administrative ($ per BOE) [1]	$ 4.03	$ 4.83	$ 12.92	$ 4.41	$ 12.56
Depreciation, depletion and amortization ($ per BOE) [2]	$ 11.99	$ 11.47	$ 10.15	$ 11.74	$ 10.02
Cash provided by operating activities [3]	$ 26,875	$ 9,142	$ 17,242	$ 36,017	$ 45,773
Cash paid for capital expenditures	$ 25,842	$ 17,741	$ 570	$ 43,583	$ 14,575
Cash and cash equivalents at end of period		$ 3,132		$ 10,105	$ 38,997
Debt outstanding at end of period		$ 30,000		$ 37,000	$ 1,187,553
Credit available under credit facility at end of period [4]		$ 97,233		$ 162,245	$ —
Net development wells drilled and completed	3.0	3.6	—	6.6	2.5

[1] Includes combined amounts of $0.92, $0.97 and $8.02 per BOE for the Successor and Predecessor three-month periods described above and $0.94 and $8.02 per BOE for the Successor and Predecessor six-month periods described above, respectively, attributable to equity-classified share-based compensation, liability-classified share-based compensation and significant special charges, including strategic and financial advisory costs incurred prior to our bankruptcy filing, among others, as described in the discussion of "*Results of Operations - General and Administrative Expenses* " that follows.

[2] Determined using the full cost method for the Successor periods and the successful efforts method for the Predecessor periods.

[3] Includes cash paid for derivative settlements of $0.5 million, $2.0 million and $2.5 million for the three and six-month Successor periods described above and cash received from derivative settlements of $16.4 million and $47.0 million for the three and six-month Predecessor periods described above, respectively.

[4] As of June 30, 2016, we were unable to draw on our pre-petition credit facility, or RBL.

Key Developments

The following general business developments had or may have a significant impact on our results of operations, financial position and cash flows:

Production and Development Plans

Total production for the second quarter of 2017 was 925 MBOE, or 10,159 barrels of oil equivalent per day, or BOEPD, with approximately 74 percent, or 685 MBOE, of production from crude oil, 14 percent from NGLs and 12 percent from natural gas. Production from our Eagle Ford operations during this period was 864 MBOE or 9,498 BOEPD. Approximately 78 percent of our Eagle Ford production for the period was from crude oil, 12 percent was from NGLs and 10 percent was from natural gas. Production from our Eagle Ford operations was approximately 93 percent of total Company production during the period.

We drilled seven gross (3.0 net) Eagle Ford wells and turned seven gross (3.0 net) wells to sales during the second quarter. During the second quarter, we turned to sales four wells from the Kudu pad, located in the northern portion of our acreage. We have an average working interest of 43.7 percent in each of the Kudu wells. The Zebra 6H and 7H wells on the two-well Zebra pad were also completed and turned to sales in the second quarter of 2017. These two wells targeted the lower Eagle Ford Shale in northern portion of our acreage. We have a 42.5 percent working interest and are the operator of both wells. Our first well, the Lager 3H, that utilized our slickwater completion design in the southeastern portion of our lower Eagle Ford Shale acreage was completed in April 2017. The Lager 3H well, in which we currently have 41.2 percent working interest, is currently producing approximately 1,000 BOEPD of which 73 percent is crude oil. As a result of the pending acquisition discussed below, we will increase our working interest in the Lager 3H well to approximately 96 percent.

Given the success of the Lager 3H well, we are accelerating drilling in the southeastern portion of our acreage. The Schacherl-Effenberger pad, which was originally designed as a one-well pad, will now be a two-well pad. These two wells are now scheduled to be drilled in the fourth quarter of 2017.

We have begun completion operations on our eight-well “super pad,” consisting of the adjoining four-well Chicken Hawk pad and the four-well Jake Berger pad. Two of the wells are targeting the upper Eagle Ford Shale/lower Austin Chalk and six wells are targeting the lower Eagle Ford Shale in the northern portion of our acreage. The wells are expected to be turned to sales in late third quarter of 2017.

Capital expenditures for 2017, including anticipated drilling expenditures associated with the pending acquisition discussed below, are expected to total between $140 and $160 million with approximately 90 percent of capital being directed to drilling and completions in the Eagle Ford.

During the quarter ended June 30, 2017, we leased and/or extended approximately 1,000 net acres increasing our core net acreage position in the volatile window of the lower Eagle Ford to approximately 57,000. Approximately 93 percent of our core acreage is held by production. We operate 336 gross wells, seven of which are currently drilling or completing, and have working interests in 42 gross outside-operated wells in the Eagle Ford as of August 4, 2017.

Acquisition of Producing Properties

In July 2017, we entered into a purchase and sale agreement, or the Purchase Agreement, with Devon Energy Corporation, or Seller, to acquire all of Seller’s rights, title and interest in and to certain oil and gas assets, or the Devon Properties, including oil and gas leases covering approximately 19,600 net acres located primarily in Lavaca, County, Texas, or the Pending Acquisition, for aggregate consideration of approximately $205 million in cash subject to customary adjustments. The Pending Acquisition has an effective date of March 1, 2017 and is expected to close in September 2017, subject to the satisfaction of specified closing conditions the failure of which may result in the transaction being terminated. Upon execution of the Purchase Agreement, we deposited $10.3 million into escrow as earnest money, which Seller may receive as liquidated damages, in lieu of seeking specific performance, if the Pending Acquisition fails to close in certain circumstances.

We intend to finance the Pending Acquisition with a combination of borrowings from our Credit Facility and new debt financing. Concurrent with the signing of the Purchase Agreement, we signed a commitment letter, pursuant to which we can elect to borrow $150.0 million in new debt financing. The commitment letter provides that such new debt financing would be funded at the closing of the Pending Acquisition and secured by a second lien on the same collateral that secures the existing Credit Facility. We expect the new debt financing to have substantially the same covenants as the existing Credit Facility and a five-year term or mature no earlier than 91 days after the maturity of the Credit Facility.

Borrowing Base Redetermination

In June 2017, the borrowing base under our Credit Facility was increased from $128 million to $200 million in connection with an amendment to the Credit Facility, or the Amendment. The Amendment also provided for a change in the composition of financial institutions comprising the Credit Facility bank group with certain participants exiting and new participants joining the group.

Commodity Hedging Program

As of August 4, 2017, including the effect of additional hedge contracts that we entered into in July 2017, we have hedged a substantial portion of our future crude oil production through the end of 2019. Our weighted-average hedge prices are approximately $48.59 per barrel for the remainder of 2017, $49.37 per barrel for 2018 and $49.75 per barrel for 2019. We are currently unhedged with respect to NGL and natural gas production.

Upon closing of the Pending Acquisition, we expect to hedge a significant portion of the oil and natural gas production associated with the acquired acreage.

Financial Condition

Liquidity

Our primary sources of liquidity include cash on hand, cash provided by operating activities and borrowings under the Credit Facility. The Credit Facility provides us with up to $200 million in borrowing commitments. The current borrowing base under the Credit Facility is $200 million. As of August 4, 2017, we had outstanding borrowings and letters of credit of $47 million and $0.8 million, respectively, resulting in $152.2 million of availability under the Credit Facility.

Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for crude oil, NGL and natural gas products, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity and other supply chain dynamics, among other factors. The level of our hedging activity and duration of the instruments employed depend on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy.

In order to mitigate this volatility, we entered into a series of derivatives contracts in May 2016 and July 2017 and hedged a substantial portion of our future crude oil production through the end of 2019. Our weighted-average hedge prices are $48.59 per barrel for the remainder of 2017, $49.37 per barrel for 2018 and $49.75 per barrel for 2019. We are currently unhedged with respect to NGL as well as natural gas production.

Capital Resources

Under our business plan, we currently anticipate capital expenditures to total between $140 million and $160 million for 2017, with approximately 90 percent of capital being directed to drilling and completions on our Eagle Ford acreage including the acreage to be acquired in the Pending Acquisition. We plan to fund our 2017 capital spending with cash from operating activities and borrowings under the Credit Facility. Based upon current price and production expectations for 2017, we believe that our cash from operating activities and borrowings under our Credit Facility will be sufficient to fund our operations through year-end 2017; however, future cash flows are subject to a number of variables and significant additional capital expenditures may be required to more fully develop our properties. We are currently in discussions with our bank lending group under the Credit Facility to further amend and increase the borrowing base beyond its current $200 million level. Our 2017 capital expenditure budget does not allocate any funds for acquisitions. As discussed above in *Key Developments*, we intend to fund the Pending Acquisition with a combination of borrowings from our Credit Facility and new committed debt financing. For a detailed analysis of our historical capital expenditures, see the “*Cash Flows*” discussion that follows.

Cash on Hand and Cash From Operating Activities. As of August 4, 2017, we had approximately $6 million of cash on hand. In addition to commodity price volatility, as discussed above, our cash from operating activities is impacted by the timing of our working capital requirements. The most significant component is drilling and completion capital expenditures and the related billing and collection of our partners’ shares thereof. This component can be substantial to the extent that we are the operator of lower working interest wells. In certain circumstances, we have and will continue to utilize capital cash calls to mitigate the burden on our working capital. For additional information and an analysis of our historical cash from operating activities, see the “*Cash Flows*” discussion that follows.

Credit Facility Borrowings. We initially borrowed $75.4 million under the Credit Facility upon our emergence from bankruptcy in September 2016. Since that time we have paid down $28.4 million, net of new borrowings through August 4, 2017. For additional information regarding the terms and covenants under the Credit Facility, see the “*Capitalization*” discussion that follows.

The following table summarizes our borrowing activity under the Credit Facility for the period presented:

	Borrowings Outstanding		
	Weighted-Average	**Maximum**	**Weighted-Average Rate**
Three months ended June 30, 2017	$ 35,522	$ 37,000	4.2315%
Six months ended June 30, 2017	$ 31,235	$ 37,000	4.0433%

Proceeds from Sales of Assets. We continually evaluate potential sales of non-core assets, including certain oil and gas properties and non-strategic undeveloped acreage, among others. For additional information and an analysis of our historical proceeds from sales of assets, see the “*Cash Flows*” discussion that follows.

Capital Market Transactions. From time-to-time and under market conditions that we believe are favorable to us, we may consider capital market transactions, including the offering of debt and equity securities.

Cash Flows

The following table summarizes our cash flows for the periods presented:

	Successor	Predecessor	2017 vs.
	Six Months Ended	Six Months Ended	2016
	June 30,	June 30,	Favorable
	2017	2016	(Unfavorable)
Cash flows from operating activities			
Operating cash flows, net of working capital changes	$ 40,171	$ 21,391	$ 18,780
Crude oil derivative settlements (paid) received, net	(2,458)	46,952	(49,410)
Interest payments, net of amounts capitalized	(795)	(2,765)	1,970
Income tax refunds	—	35	(35)
Strategic, financial and bankruptcy-related advisory fees and costs paid	(901)	(18,067)	17,166
Restructuring and exit costs paid	—	(1,773)	1,773
Net cash provided by operating activities	36,017	45,773	(9,756)
Cash flows from investing activities			
Capital expenditures	(43,583)	(14,575)	(29,008)
Proceeds from sales of assets, net	—	126	(126)
Other, net	—	1,186	(1,186)
Net cash used in investing activities	(43,583)	(13,263)	(30,320)
Cash flows from financing activities			
Proceeds (repayments) from credit facility borrowings, net	12,000	(5,468)	17,468
Debt issuance costs paid	(1,090)	—	(1,090)
Proceeds received from rights offering, net	55	—	55
Other, net	(55)	—	(55)
Net cash provided by (used in) financing activities	10,910	(5,468)	16,378
Net increase in cash and cash equivalents	$ 3,344	$ 27,042	$ (23,698)

Cash Flows from Operating Activities. The overall decline in operating cash flows was primarily attributable to the payment of cash settlements from derivatives during the Successor period in 2017 compared to the receipt of net settlements during the Predecessor period in 2016. Specifically, our hedged prices for maturing contracts have exceeded the West Texas Intermediate, or WTI, crude oil prices on our post-petition derivatives resulting in net payments in the 2017 Successor period while the opposite situation occurred in the Predecessor period in 2016 resulting in receipt of cash settlements as well as the early termination of certain pre-petition derivative contracts in the Predecessor period in 2016 which accelerated the receipt of cash settlements. In addition, we experienced higher working capital utilization in the Successor period in 2017 as a result of the restart of our drilling program, which had been suspended in February 2016. These decreases were substantially offset by the effect of: (i) higher pricing resulting in higher overall product revenue receipts in the 2017 Successor period, (ii) substantially higher payments in 2016 for professional fees and other costs associated with our bankruptcy proceedings and consideration of strategic financing alternatives in advance thereof, (iii) payments for termination benefits and other exit activities in the 2016 Predecessor period and (iv) lower interest payments due to lower outstanding borrowings under the Credit Facility in the 2017 Successor period as compared to outstanding borrowings under the RBL in the Predecessor period in 2016.

Cash Flows from Investing Activities. As illustrated in the tables below, our cash payments for capital expenditures were higher during the Successor period in 2017 as compared to the Predecessor period in 2016 due primarily to the restart of our Eagle Ford drilling program. Furthermore, the cash paid for capital expenditures in the Predecessor period in 2016 includes a higher portion attributable to settlements of accrued capital charges from the prior year-end period. The Predecessor period in 2016 also includes insurance recoveries from a casualty loss incurred in 2015.

The following table sets forth costs related to our capital expenditures program for the periods presented:

	Successor	Predecessor
	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Drilling and completion	$ 43,455	$ 3,784
Lease acquisitions and other land-related costs	1,402	54
Pipeline, gathering facilities and other equipment	(443)	363
Geological, geophysical (seismic) and delay rental costs	382	(17)
	$ 44,796	$ 4,184

The following table reconciles the total costs of our capital expenditures program with the net cash paid for capital expenditures as reported in our Condensed Consolidated Statements of Cash Flows for the periods presented:

	Successor	Predecessor
	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Total capital expenditures program costs (from above)	$ 44,796	$ 4,184
(Increase) decrease in accrued capitalized costs	(2,322)	10,555
Less:		
Exploration costs charged to operations [1]:		
Geological, geophysical (seismic) and delay rental costs	—	17
Transfers from tubular inventory and well materials	(1,142)	(528)
Add:		
Tubular inventory and well materials purchased in advance of drilling	1,100	164
Capitalized internal labor [1]	1,070	—
Capitalized interest	81	183
Total cash paid for capital expenditures	$ 43,583	$ 14,575

[1] Exploration costs and certain internal labor costs were charged to operations while we applied the successful efforts method in the 2016 Predecessor period and capitalized under the full cost method in the 2017 Successor period.

Cash Flows from Financing Activities. The Successor period in 2017 includes borrowings of $14 million and repayments of $2 million under the Credit Facility while the Predecessor period in 2016 includes repayments of $5.5 million under the RBL. We also paid $1.1 million of debt issue costs in June 2017 in connection with the Amendment. Delayed receipts attributable to the rights offering in September 2016 were offset by costs paid in connection with the registration of our common stock in the Successor period in 2017.

Capitalization

The following table summarizes our total capitalization as of the date presented:

	June 30, 2017	December 31, 2016
Credit Facility borrowings	$ 37,000	$ 25,000
Shareholders' equity	236,696	185,548
	$ 273,696	$ 210,548
Debt as a % of total capitalization	14%	12%

Credit Facility. The Credit Facility provides for a $200 million revolving commitment and borrowing base. The Credit Facility includes a $5 million sublimit for the issuance of letters of credit. The availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base. The borrowing base under the Credit Facility is generally redetermined semi-annually in April and October of each year. Additionally, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us to pay expenses associated with our bankruptcy proceedings and for general corporate purposes including working capital. The Credit Facility matures in September 2020.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate, or LIBOR, plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on LIBOR borrowings is payable every one, three or six months, at our election, and is computed on the basis of a year of 360 days. As of June 30, 2017, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 4.3289%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by our parent company and all of our subsidiaries, or the Guarantor Subsidiaries. The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. The parent company has no material independent assets or operations. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our assets.

Covenant Compliance. The Credit Facility requires us to maintain (1) a minimum interest coverage ratio (adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses as defined in the Credit Facility, or EBITDAX, to adjusted interest expense), measured as of the last day of each fiscal quarter, of 3.00 to 1.00, (2) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00, and (3) a maximum leverage ratio (consolidated indebtedness to EBITDAX), measured as of the last day of each fiscal quarter, initially of 4.00 to 1.00, decreasing on December 31, 2017 to 3.75 to 1.00 and on March 31, 2018 and thereafter to 3.50 to 1.00.

The Credit Facility also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

The Credit Facility contains customary events of default and remedies for credit facilities of this nature. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility.

As of June 30, 2017, we were in compliance with all of these covenants.

Results of Operations

As discussed previously in the *Overview and Executive Summary*, the adoption of Fresh Start Accounting and the full cost method of accounting for oil and gas properties upon our emergence from bankruptcy results in the Successor not being comparable to the Predecessor for purposes of financial reporting. While the Successor effectively represents a new reporting entity for financial reporting purposes, the impact is limited to those areas associated with the basis in and accounting for our oil and gas properties (specifically DD&A, impairments as well as exploration expenses), general and administrative expenses due to the capitalization of certain labor costs under the full cost method, capital structure (specifically interest expense) and income taxes (due to the change in control). Accordingly, we believe that describing certain year-over-year variances and trends in our production, revenues and expenses for the three and six months ended June 30, 2017 and 2016 without regard to the concept of a Successor and Predecessor continues to facilitate a meaningful analysis of our results of operations.

Production

The following tables set forth a summary of our total and daily production volumes by product and geographic region for the periods presented:

	Total Production			Average Daily Production		
	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
	(Total volume)			(Volume per day)		
Crude oil (MBbl & BOPD)	685	791	(106)	7,524	8,692	(1,168)
NGLs (MBbl and BOPD)	131	187	(56)	1,440	2,053	(613)
Natural gas (MMcf and MMcfpd)	653	1,070	(417)	7	12	(5)
Total (MBOE and BOEPD)	925	1,156	(232)	10,159	12,706	(2,546)

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
	(MBOE)			(BOE per day)		
South Texas	864	1,055	(191)	9,498	11,595	(2,098)
Mid-Continent and other [1]	60	101	(41)	662	1,110	(448)
	925	1,156	(232)	10,159	12,706	(2,546)

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
	(Total volume)			(Volume per day)		
Crude oil (MBbl & BOPD)	1,293	1,764	(471)	7,142	9,692	(2,550)
NGLs (MBbl and BOPD)	250	400	(150)	1,382	2,200	(819)
Natural gas (MMcf and MMcfpd)	1,418	2,318	(900)	8	13	(5)
Total (MBOE and BOEPD)	1,779	2,551	(772)	9,829	14,014	(4,185)

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
	(MBOE)			(BOE per day)		
South Texas	1,635	2,346	(712)	9,032	12,892	(3,860)
Mid-Continent and other [1]	144	204	(60)	797	1,122	(325)
	1,779	2,551	(772)	9,829	14,014	(4,185)

[1] Includes total production and average daily production of approximately 4 MBOE (50 BOEPD) and 9 MBOE (51 MBOE) attributable to our currently inactive Marcellus Shale wells for the three and six months ended June 30, 2016.

Total production decreased during the three and six month periods in 2017 when compared to the corresponding 2016 periods due primarily to the suspension of our drilling program in February 2016 and natural production declines. While we resumed the drilling program in November 2016, we did not turn any new wells to sales until mid-February 2017. Approximately 74 percent and 73 percent of total production during the three and six month periods in 2017 was attributable to oil when compared to approximately 68 percent 69 percent during the corresponding periods in 2016. Our Eagle Ford production represented 93 percent and 92 percent of our total production during the three and six month periods in 2017 compared to approximately 91 percent and 92 percent from this region during the corresponding period in 2016. During the three and six month periods in 2017, we turned seven and 13 gross Eagle Ford wells to sales compared to none in the three month 2016 period and five gross wells during the six month 2016 period.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product and geographic region for the periods presented:

	Total Product Revenues			Product Revenues per Unit of Volume		
	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
					($ per unit of volume)	
Crude oil	$ 32,351	$ 32,019	$ 332	$ 47.25	$ 40.48	$ 6.77
NGLs	2,043	2,431	(388)	$ 15.59	$ 13.01	$ 2.58
Natural gas	1,880	1,917	(37)	$ 2.88	$ 1.79	$ 1.09
Total	$ 36,274	$ 36,367	$ (93)	$ 39.24	$ 31.45	$ 7.79
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
					($ per BOE)	
South Texas	$ 34,916	$ 34,646	$ 270	$ 40.40	$ 32.83	$ 7.57
Mid-Continent and other [1]	1,358	1,721	(363)	$ 22.55	$ 17.04	$ 5.51
	$ 36,274	$ 36,367	$ (93)	$ 39.24	$ 31.45	$ 7.79
	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
					($ per unit of volume)	
Crude oil	$ 62,424	$ 57,985	$ 4,439	$ 48.29	$ 32.87	$ 15.42
NGLs	4,345	4,384	(39)	$ 17.38	$ 10.95	$ 6.43
Natural gas	4,223	4,319	(96)	$ 2.98	$ 1.86	$ 1.12
Total	$ 70,992	$ 66,688	$ 4,304	$ 39.90	$ 26.15	$ 13.75
	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
					($ per BOE)	
South Texas	$ 67,603	$ 63,401	$ 4,202	$ 41.35	$ 27.02	$ 14.33
Mid-Continent and other [1]	3,389	3,287	102	$ 23.49	$ 16.09	$ 7.40
	$ 70,992	$ 66,688	$ 4,304	$ 39.90	$ 26.15	$ 13.75

[1] Includes revenues of less than $0.1 million and $0.1 million attributable to our currently inactive Marcellus Shale wells for the three and six months ended March 31, 2016.

The following table provides an analysis of the changes in our revenues for the periods presented:

	Three Months Ended June 30, 2017 vs. 2016			Six Months Ended June 30, 2017 vs. 2016		
	Revenue Variance Due to			Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ (4,303)	$ 4,635	332	$ (15,495)	$ 19,934	4,439
NGLs	(726)	338	(388)	(1,646)	1,607	(39)
Natural gas	(748)	711	(37)	(1,676)	1,580	(96)
	$ (5,777)	$ 5,684	$ (93)	$ (18,817)	$ 23,121	$ 4,304

Our product revenues were relatively consistent for the three month period in 2017 compared to the corresponding period in 2016. Our product revenues during the six month period in 2017 increased over the corresponding period in 2016 due primarily to the significant increases in all product pricing which was somewhat offset by the decline in production described previously. Total crude oil revenues were approximately 89 percent and 88 percent during the three and six month periods in 2017 as compared to 88 percent and 88 percent during the corresponding periods in 2016. Total Eagle Ford revenues were approximately 96 percent and 95 percent of total revenues for the three and six month periods in 2017and 95 percent for each of the corresponding periods in 2016, respectively.

Effects of Derivatives

The following table reconciles crude oil revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Crude oil revenues, as reported	$ 32,351	$ 32,019	$ 332	$ 62,424	$ 57,985	$ 4,439
Derivative settlements, net	(466)	16,393	(16,859)	(2,458)	46,952	(49,410)
	$ 31,885	$ 48,412	$ (16,527)	$ 59,966	$ 104,937	$ (44,971)
Crude oil prices per Bbl	$ 47.25	$ 40.48	$ 6.77	$ 48.29	$ 32.87	$ 15.42
Derivative settlements per Bbl	(0.68)	20.72	(21.40)	(1.90)	26.62	(28.52)
	$ 46.57	$ 61.20	$ (14.63)	$ 46.39	$ 59.49	$ (13.10)

Gain (Loss) on the Sales of Assets

We recognize gains and losses on the sale or disposition of assets other than our oil and gas properties upon the completion of the underlying transactions. The following table sets for the total gains and losses recognized for the periods presented:

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
(Loss) gain on sales of assets, net	$ (134)	$ 910	$ (1,044)	$ (69)	$ 757	$ (826)

There were insignificant net losses recognized during the three and six month 2017 periods attributable to support equipment and tubular inventory and well materials. The three and six month 2016 periods reflect the amortization of deferred gains from our 2014 transactions associated with the sale of crude oil and natural gas gathering assets in South Texas. The unamortized portions of those deferred gains were ultimately reversed from our Condensed Consolidated Balance Sheet in connection with our application of Fresh Start Accounting in September 2016.

Other Revenues, net

Other revenues, net, includes fees for marketing, water disposal, gathering, transportation and compression that we charge to third parties, net of related expenses as well as other miscellaneous revenues and credits attributable to our operations. During the Predecessor periods, these revenues also included fees for water supply services as well as charges for accretion attributable to our unused firm transportation obligation.

The following table sets forth the total other revenues, net recognized for the periods presented:

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Other revenues, net	$ 142	$ (125)	$ 267	$ 345	$ 204	$ 141

Other revenues, net increased during the three and six month periods in 2017 from the corresponding periods in 2016 due primarily to higher marketing fees partially offset by lower water disposal fees resulting from lower overall production. Included in the three and six month periods in 2016 were charges of $0.1 million and $0.3 million attributable to the accretion of unused firm transportation while there were no such charges in the 2017 periods as the underlying obligation was rejected in our bankruptcy proceedings.

Lease Operating Expense

Lease operating expense, or LOE, includes costs that we incur to operate our producing wells and field operations. The most significant costs include compression and gas-lift, chemicals, water disposal, repairs and maintenance, including down-hole repairs, field labor, pumping and well-tending, equipment rentals, utilities and supplies, among others.

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Lease operating	$ 5,370	$ 5,225	$ (145)	$ 10,286	$ 11,417	$ 1,131
Per unit of production ($/BOE)	$ 5.81	$ 4.52	$ (1.29)	$ 5.78	$ 4.48	$ (1.30)
% Change per unit of production			(29)%			(29)%

LOE increased on a per unit basis during the three and six month periods in 2017 when compared to the corresponding periods in 2016 due primarily to certain costs associated with maintaining our portfolio of operating wells, which are less variable in nature and are therefore adversely affected by lower production volume, as well as higher surface and other repair and maintenance costs. While we incurred higher such repair costs in the three and six month periods in 2017, they were partially offset by continuing cost containment efforts that we implemented throughout 2016 and into 2017 as well as the effects of lower industry-wide pricing for certain oilfield products and services.

Gathering, Processing and Transportation

Gathering, processing and transportation, or GPT, includes costs that we incur to gather and aggregate our oil, NGL and natural gas production from our wells and deliver them to a central delivery point, downstream pipelines or processing plants, depending upon the type of production and the specific arrangements that we have with midstream operators.

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Gathering, processing and transportation	$ 2,555	$ 4,650	$ 2,095	$ 5,106	$ 8,468	$ 3,362
Per unit of production ($/BOE)	$ 2.77	$ 4.02	$ 1.25	$ 2.87	$ 3.32	$ 0.45
% Change per unit of production			31%			14%

GPT decreased during the three and six month periods in 2017 when compared to the corresponding periods in 2016 due primarily to substantially lower production volumes as discussed above. Per unit rates were favorably impacted by an amendment to our gathering agreement with Republic Midstream, LLC that became effective in August of 2016. Prior to that time we had incurred charges for production falling below our minimum commitments which were previously higher. We also incurred costs in the three and six month periods in 2016 for unused firm transportation services in the Marcellus Shale prior to our termination of operations in that region. There were no such costs incurred in the periods in 2017 as the underlying contracts were rejected in our bankruptcy proceedings.

Production and Ad Valorem Taxes

Production or severance taxes represent taxes imposed by the states in which we operate for the removal of resources including crude oil, NGLs and natural gas. Ad valorem taxes represent taxes imposed by certain jurisdictions, primarily counties, in which we operate, based on the value of our operating properties. The assessments for ad valorem taxes are generally based on contemporary commodity prices.

	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Production and ad valorem taxes						
Production/severance taxes	$ 1,698	$ 1,184	$ (514)	$ 3,353	$ 1,380	$ (1,973)
Ad valorem taxes	421	979	558	745	1,536	791
	$ 2,119	$ 2,163	$ 44	$ 4,098	$ 2,916	$ (1,182)
Per unit production ($/BOE)	$ 2.29	$ 1.87	$ (0.42)	$ 2.30	$ 1.14	$ (1.16)
Production/severance tax rate as a percent of product revenue	4.7%	3.3%		4.7%	2.1%	

Production taxes increased on both an absolute and per unit basis during the three and six month periods in 2017 when compared to the corresponding periods in 2016 due primarily to the recognition of certain severance tax refunds from Oklahoma in the 2016 periods that were attributable to prior years, as well as higher commodity sales prices despite a decline in production volume in the Successor periods in 2017. In the latter half of 2016 and into 2017, we adjusted our accruals for ad valorem taxes downward, primarily in South Texas, reflecting lower oil and gas property valuations.

General and Administrative

The following table sets forth the components of our general and administrative expenses, or G&A, for the periods presented:

	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Primary G&A	$ 2,873	$ 5,671	$ 2,798	$ 6,174	$ 11,570	$ 5,396
Share-based compensation						
Liability-classified	—	(12)	(12)	—	(19)	(19)
Equity-classified [1]	848	1,965	1,117	1,694	1,364	(330)
Significant special charges:						
Strategic and financial advisory costs	—	6,973	6,973	—	18,036	18,036
Restructuring expenses	—	351	351	(20)	1,099	1,119
Total G&A	$ 3,721	$ 14,948	$ 11,227	$ 7,848	$ 32,050	$ 24,202
Per unit of production ($/BOE)	$ 4.03	$ 12.92	$ 8.89	$ 4.41	$ 12.56	$ 8.15
Per unit of production excluding all share-based compensation and other significant special charges identified above ($/BOE)	$ 3.11	$ 4.90	$ 1.79	$ 3.47	$ 4.54	$ 1.07

[1] As described in Notes 2 and 14 to the Condensed Consolidated Financial Statements, the amounts for the 2016 periods have been recasted.

Our primary G&A expenses decreased on an absolute and per unit basis during the three and six month periods in 2017 compared to the corresponding 2016 periods. The decrease is due primarily to the effects of: (i) lower payroll and benefits attributable to lower employee headcount, (ii) the capitalization of certain labor and benefits costs to oil and gas properties in accordance with the full cost method in 2017 (iii) the relocation of our headquarters from Radnor, Pennsylvania to Houston, Texas and related move to a smaller office location, (iv) reduced travel and entertainment and (v) lower corporate support costs consistent with our efforts throughout the 2016 and into 2017 to reduce our support cost base.

Liability-classified share-based compensation in the 2016 periods was attributable to our former performance-based restricted stock units, or PBRSUs, and represents mark-to-market adjustments associated with the change in fair value of the then outstanding PBRSU grants. Our common stock performance relative to a defined peer group was less favorable during the 2016 periods resulting in a mark-to-market reversal. All of the unvested PBRSUs were canceled upon our emergence from bankruptcy.

Equity-classified share-based compensation charges during the period in 2017 are attributable to the grants of time-vested restricted stock units, or RSUs, in the fourth quarter of 2016 and the first quarter of 2017 as well as performance restricted stock units, or PRSUs, in the first quarter of 2017. The 2017 grants of RSUs and PRSUs are described in greater detail in Note 14 to the Condensed Consolidated Financial Statements. The 2016 periods include a charge for the cancellation of all of the RSUs outstanding prior to our bankruptcy filing in May 2016 partially offset by forfeitures of the Predecessor's stock options. All of our equity-classified share-based compensation represents non-cash expenses.

During the periods in 2016, we incurred substantial professional fees and other consulting costs associated with our consideration of strategic financing alternatives and related activities in advance of our bankruptcy filing. In connection with our efforts to simplify and reduce our administrative cost structure, we terminated a total of 10 employees in February of 2016 and an additional 18 employees in June 2016 and incurred related termination and severance benefit costs during the Predecessor periods.

Exploration

While applying the successful efforts method of accounting to our oil and gas properties during the Predecessor periods in 2016, we incurred costs which were charged to operations in accordance with the successful efforts method. In the Successor periods, we applied the full cost method of accounting whereby these costs are capitalized. See the discussion of our capital expenditures program included in "Financial Condition - *Cash Flows*" above and Note 6 to the Condensed Consolidated Financial Statements for a discussion of certain capitalized costs. The following table sets forth the components of exploration expense for the Predecessor periods presented:

	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Unproved leasehold amortization	$ —	$ 857	$ 857	$ —	$ 1,713	$ 1,713
Drilling rig termination charges	—	936	936	—	1,426	1,426
Drilling carry commitment	—	1,964	1,964	—	1,964	1,964
Geological and geophysical costs	—	—	—	—	33	33
Other, primarily delay rentals	—	563	563	—	511	511
	$ —	$ 4,320	$ 4,320	$ —	$ 5,647	$ 5,647

In addition to normal exploration costs associated with the successful efforts method in the Predecessor periods in 2016, primarily unproved leasehold amortization, in the three months ended June 30, 2016, we incurred: (i) early termination charges in connection with the release of a drilling rig in the Eagle Ford, (ii) charges for the failure to complete a drilling carry commitment attributable to certain acreage acquired in the Eagle Ford and (iii) a charge for coiled tubing services that were not utilized by the contract expiration date.

Depreciation, Depletion and Amortization (DD&A)

As discussed with respect to exploration expenses above, our adoption of the full cost method in place of the successful efforts method of accounting for oil and gas properties also impacted the determination of our DD&A during the Successor periods in 2017 as compared to the Predecessor periods in 2016. The following table sets forth total and per unit costs for DD&A:

	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
DD&A expense	$ 11,076	$ 11,746	$ 670	$ 20,886	$ 25,558	$ 4,672
DD&A Rate ($/BOE)	$ 11.99	$ 10.15	$ (1.84)	$ 11.74	$ 10.02	$ (1.72)

The effects of lower production volumes net of the effects of higher depletion rates were the primary factors attributable to the decline in DD&A during the periods in 2017 when compared to the periods in 2016. The DD&A rates and the underlying reserves and cost bases are not comparable due to the utilization of different methods as described above.

Interest Expense

The following table summarizes the components of our interest expense for the periods presented:

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Interest on borrowings and related fees	$ 515	$ 11,344	$ 10,829	$ 905	$ 34,649	$ 33,744
Amortization of debt issuance costs	800	20,920	20,120	988	22,189	21,201
Capitalized interest	(41)	(43)	(2)	(81)	(183)	(102)
	$ 1,274	$ 32,221	$ 30,947	$ 1,812	$ 56,655	$ 54,843

Interest expense during the three and six month periods in 2017 is exclusively attributable to the Credit Facility. Interest expense during the corresponding periods in 2016 is attributable to the RBL and our former 7.25% Senior Notes due 2019 and 8.50% Senior Notes due 2020, or the Senior Notes. Interest on the Senior Notes was charged through the date of our bankruptcy filing in May 2016 upon which time the accrual of interest was suspended. Amortization of debt issuance costs in the 2017 periods included a write-off of $0.6 million attributable to previously capitalized debt issue costs due to a change in the composition of financial institutions comprising the Credit Facility bank group while the 2016 periods included a $20.5 million accelerated write-off of issue costs associated with the RBL and Senior Notes in advance of our bankruptcy filing. Notwithstanding these write-offs, the overall decrease is due to substantially higher outstanding indebtedness during the 2016 periods.

Derivatives

The following table summarizes the gains and (losses) attributable to our commodity derivatives portfolio, by commodity type, for the periods presented:

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Crude oil derivative gains (losses)	$ 11,061	$ (21,759)	$ 32,820	$ 28,077	$ (17,267)	$ 45,344
Natural gas derivative gains (losses)	—	—	—	—	—	—
	$ 11,061	$ (21,759)	$ 32,820	$ 28,077	$ (17,267)	$ 45,344

The gains and losses for our derivatives portfolio reflect changes in the fair value attributable to changes in market values relative to our hedged commodity prices. We paid cash settlements of $0.5 million and $2.5 million in the three and six-month periods in 2017 as compared to the receipt of $16.4 million and $47.0 million of cash settlements from crude oil derivatives during the three and six-month periods in 2016. The changes in total cash settlements is attributable to the payment of cash settlements from derivatives during the periods in 2017 compared to the receipt of net settlements during the periods in 2016. Specifically, our hedged prices for maturing contracts have exceeded the West Texas Intermediate, or WTI, crude oil prices on our post-petition derivatives resulting in net payments in the periods in 2017 while the opposite situation occurred in the periods in 2016 resulting in receipt of cash settlements as well as the early termination of certain pre-petition derivative contracts in the periods in 2016 which accelerated the receipt of cash settlements.

Other, net

The following table sets forth the other income (expense), net recognized for the periods presented:

	Successor Three Months Ended June 30, 2017	Predecessor Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Successor Six Months Ended June 30, 2017	Predecessor Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Other, net	$ 101	$ (6)	$ 107	$ 101	$ (1,030)	$ 1,131

In the periods in 2017, we recovered certain costs attributable to assets that were sold in prior years. In the periods in 2016 we wrote-off unrecoverable amounts from prior years, including GPT charges and other revenue deductions, attributable primarily to properties that had been sold.

Reorganization Items, net

The following table summarizes the components included in Reorganization items, net for the periods presented:

	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Legal and professional fees and expenses	$ —	$ 7,237	$ 7,237	$ —	$ 7,237	$ 7,237
Debtor-in-Possession credit facility costs and commitment fees	—	143	143	—	143	143
	$ —	$ 7,380	$ 7,380	$ —	$ 7,380	$ 7,380

Reorganization items, net includes costs incurred in connection with the Predecessor's bankruptcy proceedings including professional fees for attorneys, financial consultants, claims processors and others as well as fees associated with establishing the Predecessor's debtor-in-possession credit facility as well as commitment fees for the period from the date the facility was established in May 2016 through June 30, 2016.

Income Taxes

The following table sets forth the income tax benefit (expense) recognized for the periods presented:

	Successor	Predecessor		Successor	Predecessor	
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	2017 vs. 2016 Favorable (Unfavorable)
Income tax benefit (expense)	$ —	$ —	$ —	$ —	$ —	$ —
Effective tax rate	—%	—%		—%	—%	

We recognized a federal and state income tax expense for the three and six month periods in 2017 at the blended rate of 35.52%; however, the federal and state tax expense was fully offset by an adjustment to the valuation allowance against our net deferred tax assets. We recognized a federal income tax benefit for the three and six months ended June 30, 2016 at the statutory rate of 35% which was fully offset by a valuation allowance against our net deferred tax assets. We considered both the positive and negative evidence in determining that it was more likely than not that some portion or all of our deferred tax assets will not be realized, primarily as a result of our cumulative losses. We received a state income tax refund of less than $0.1 million during the six month period ended June 30, 2016.

We have evaluated the impact of the reorganization, including the change in control, resulting from our emergence from bankruptcy. From an income tax perspective, the most significant impact is attributable to our carryover tax attributes associated with our net operating losses, or NOLs. We believe that the Successor will be able to fully absorb the cancellation of debt income realized by the Predecessor in connection with the reorganization with its adjusted NOL carryovers. The amount of the remaining NOL carryovers and the tax basis of our properties will be limited under Section 382 of the Internal Revenue Code due to the change in control that occurred upon our emergence from bankruptcy. As the tax basis of our assets, primarily our oil and gas properties, is in excess of the carrying value, as adjusted in the Fresh Start Accounting process, the Successor is in a net deferred tax asset position. We have determined that it is more likely than not that we will not realize future income tax benefits from the additional tax basis and our remaining NOL carryovers. Accordingly, we have provided for a full valuation allowance of the underlying deferred tax assets.

Off Balance Sheet Arrangements

As of June 30, 2017, we had no off-balance sheet arrangements other than lease arrangements, information technology licensing, service agreements, employment agreements and letters of credit, all of which are customary in our business.

Critical Accounting Estimates

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America, or GAAP, requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. Disclosure of our most critical accounting estimates that involve the judgment of our management can be found in our Annual Report on Form 10-K for the year ended December 31, 2016.

As described in Note 2 to our Condensed Consolidated Financial Statements, we applied Fresh Start Accounting to our Condensed Consolidated Financial Statements and we also adopted the full cost method of accounting for our oil and gas properties upon our emergence from bankruptcy in September 2016.

Disclosure of the Impact of Recently Issued Accounting Standards to be Adopted in the Future

In March 2017, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, 2017–07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, or ASU 2017–07, which provides guidance to improve the reporting of net benefit cost in financial statements. The guidance requires employers to disaggregate the service cost component from the other components of net benefit cost. The service cost component of net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period, except for amounts capitalized. All other components of net benefit cost shall be presented outside of a subtotal for income from operations. The line item used to present the components other than the service cost shall be disclosed if the other components are not presented in a separate line item or items. ASU 2017–07 is effective January 1, 2018 and is required to be applied retrospectively. ASU 2017–07 will be applicable to our legacy retiree benefit plans which cover a limited population of former employees. There is no service cost associated with these plans as they are not applicable to current employees, but rather “interest and other costs” associated with the legacy obligations. Upon the adoption of ASU 2017–07, the entirety of the expense associated with these plans will be presented as a component of the “Other income (expense)” caption in our Condensed Consolidated Statement of Operations. These costs are currently recognized as a component of “General and administrative” expenses. The total cost associated with these plans is generally less than $0.1 million on an annual basis and is therefore not material. We will adopt ASU 2017–07 in January 2018.

In June 2016, the FASB issued ASU 2016–13, *Measurement of Credit Losses on Financial Instruments*, or ASU 2016–13, which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold, (an “incurred loss” model), ASU 2016–13 mandates an “expected loss” model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and reasonable supported forecasts and (iv) has no recognition threshold. ASU 2016–13 will have applicability to our accounts receivable portfolio, particularly those receivables attributable to our joint interest partners. At this time, we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures; however, we are currently in the early stages of evaluating the requirements and the period for which we will adopt the standard.

In February 2016, the FASB issued ASU 2016–02, *Leases*, or ASU 2016–02, which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than twelve months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–02 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASU 2016–02 is January 1, 2019, with early adoption permitted. We believe that ASU 2016–02 will likely be applicable to our oil and natural gas gathering commitment arrangements as described in Note 12 to the Condensed Consolidated Financial Statements, our existing leases for office facilities and certain office equipment and potentially to certain drilling rig and completion contracts with terms in excess of twelve months to the extent we may have such contracts in the future. Our oil and natural gas gathering arrangements are fairly complex and involve multiple elements that could be construed as leases. Accordingly, we are continuing to evaluate the effect that ASU 2016–02 will have on our Consolidated Financial Statements and related disclosures as well as the period for which we will adopt the standard, however, at this time, we believe that we will likely adopt ASU 2016–02 in 2019.

In May 2014, the FASB issued ASU 2014–09, *Revenues from Contracts with Customers*, or ASU 2014–09, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. While traditional commodity sales transactions, property conveyances and joint interest arrangements in the oil and gas industry are not expected to be significantly impacted by ASU 2014–09, natural gas imbalances and other non-product revenues, including our ancillary marketing, gathering and transportation and water disposal revenues could be affected. Accordingly, we are continuing to evaluate the effect that ASU 2014–09 will have on our Consolidated Financial Statements and related disclosures, with a more focused analysis on these other revenue sources, which we do not believe are significant. We are also continuing to monitor developments regarding ASU 2014–09 that are unique to our industry. We will adopt ASU 2014–09 in January 2018 using the cumulative effect transition method.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Not required for smaller reporting companies.

Item 4. ***Controls and Procedures***

(a) Disclosure Controls and Procedures

Our management, with the participation of our Principal Executive Officer and our Chief Financial Officer, performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of June 30, 2017. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported on a timely basis and that such information is accumulated and communicated to management, including our Principal Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, our Principal Executive Officer and our Chief Financial Officer concluded that, as of June 30, 2017, such disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

During the three months ended June 30, 2017, no changes were made in our internal control over financial reporting 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***

On May 12, 2016, we and the Chapter 11 Subsidiaries filed voluntary petitions (*In re Penn Virginia Corporation, et al. Case No. 16-32395*) seeking relief under the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Virginia.

On August 11, 2016, the Bankruptcy Court confirmed our Plan, and we subsequently emerged from bankruptcy on September 12, 2016. See Note 4 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data," for a more detailed discussion of our bankruptcy proceedings.

On February 7, 2017, a former shareholder of the Company filed a Complaint in the Bankruptcy Court requesting that the Bankruptcy Court set aside its prior order confirming the Plan, previously confirmed on August 11, 2016. We filed a motion to dismiss the proceeding which was granted by the Bankruptcy Court on July 21, 2017. The former shareholder filed a notice of appeal to the U.S. District Court for the Eastern District of Virginia on July 27, 2017. As reflected by the Bankruptcy Court's ruling, we believe this matter is without merit and will defend confirmation of the Plan. Absent a reversal of the Bankruptcy Court's decision, this matter has no impact on the order confirming the Plan.

See Note 12 to our Condensed Consolidated Financial Statements included in Part I, Item 1, "Financial Statements." We are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Item 1A. ***Risk Factors***

There have been no material changes to the risk factors disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016.

Item 6. ***Exhibits***

(10.1)	Master Assignment, Agreement and Amendment No. 2 to Credit Agreement dated as of June 27, 2017 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 30, 2017).
(31.1) *	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2) *	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1) †	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2) †	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(101.INS) *	XBRL Instance Document
(101.SCH) *	XBRL Taxonomy Extension Schema Document
(101.CAL) *	XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF) *	XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB) *	XBRL Taxonomy Extension Label Linkbase Document
(101.PRE) *	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.
† Furnished herewith.

SIGNATURES

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

PENN VIRGINIA CORPORATION
(Registrant)

By: /s/ STEVEN A. HARTMAN August 9, 2017
Steven A. Hartman
Senior Vice President, Chief Financial Officer and Treasurer

By: /s/ TAMMY L. HINKLE August 9, 2017
Tammy L. Hinkle
Vice President and Controller
(Principal Accounting Officer)

Exhibit 31.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, John A. Brooks, Interim Principal Executive Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this "Report");

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: August 9, 2017

/s/ JOHN A. BROOKS

John A. Brooks
Interim Principal Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven A. Hartman, Senior Vice President, Chief Financial Officer and Treasurer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this "Report");

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: August 9, 2017

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Penn Virginia Corporation (the “Company”) on Form 10-Q for the six months ended June 30, 2017, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, John A. Brooks, Interim Principal Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 9, 2017

/s/ JOHN A. BROOKS

John A. Brooks
Interim Principal Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Penn Virginia Corporation (the "Company") on Form 10-Q for the six months ended June 30, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Steven A. Hartman, Senior Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 9, 2017

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President, Chief Financial Officer and Treasurer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.