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 March 31, 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

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 May 5, 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 March 31, 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
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Revenues		
Crude oil	$ 30,073	$ 25,966
Natural gas liquids	2,302	1,953
Natural gas	2,343	2,402
Gain (loss) on sales of assets, net	65	(153)
Other, net	602	329
Total revenues	35,385	30,497
Operating expenses		
Lease operating	4,989	6,192
Gathering, processing and transportation	2,551	3,818
Production and ad valorem taxes	1,979	753
General and administrative	4,127	17,102
Exploration	—	1,327
Depreciation, depletion and amortization	9,810	13,812
Total operating expenses	23,456	43,004
Operating income (loss)	11,929	(12,507)
Other income (expense)		
Interest expense	(538)	(24,434)
Derivatives	17,016	4,492
Other, net	—	(1,024)
Income (loss) before income taxes	28,407	(33,473)
Income tax benefit (expense)	—	—
Net income (loss)	28,407	(33,473)
Preferred stock dividends	—	(3,152)
Net income (loss) attributable to common shareholders	$ 28,407	$ (36,625)
Net income (loss) per share:		
Basic	$ 1.89	$ (0.43)
Diluted	$ 1.88	$ (0.43)
Weighted average shares outstanding – basic	14,992	85,941
Weighted average shares outstanding – diluted	15,126	85,941

See accompanying notes to condensed consolidated financial statements.

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

	Successor	Predecessor
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Net income (loss)	$ 28,407	$ (33,473)
Other comprehensive loss:		
Change in pension and postretirement obligations, net of tax $0 in 2016	—	(27)
	—	(27)
Comprehensive income (loss)	$ 28,407	$ (33,500)

See accompanying notes to condensed consolidated financial statements.

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

	March 31, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$ 3,132	$ 6,761
Accounts receivable, net of allowance for doubtful accounts	38,667	29,095
Other current assets	3,110	3,028
Total current assets	44,909	38,884
Property and equipment, net (full cost method)	258,326	247,473
Other assets	5,176	5,329
Total assets	$ 308,411	$ 291,686
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 51,124	$ 49,697
Derivative liabilities	4,667	12,932
Total current liabilities	55,791	62,629
Other liabilities	4,136	4,072
Derivative liabilities	3,694	14,437
Long-term debt	30,000	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 March 31, 2017 and December 31, 2016	150	150
Paid-in capital	191,456	190,621
Retained earnings (accumulated deficit)	23,111	(5,296)
Accumulated other comprehensive income	73	73
Total shareholders' equity	214,790	185,548
Total liabilities and shareholders' equity	$ 308,411	$ 291,686

See accompanying notes to condensed consolidated financial statements.

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

	Successor		Predecessor	
	Three Months Ended March 31, 2017		Three Months Ended March 31, 2016	
Cash flows from operating activities				
Net income (loss)	$	28,407	$	(33,473)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion and amortization		9,810		13,812
Accretion of firm transportation obligation		—		175
Derivative contracts:				
Net gains		(17,016)		(4,492)
Cash settlements, net		(1,992)		30,559
(Gain) loss on sales of assets, net		(65)		153
Non-cash exploration expense		—		856
Non-cash interest expense		188		1,269
Share-based compensation (equity-classified)		846		(602)
Other, net		18		(4)
Changes in operating assets and liabilities, net		(10,728)		20,278
Net cash provided by operating activities		9,468		28,531
Cash flows from investing activities				
Capital expenditures		(18,067)		(14,005)
Proceeds from sales of assets, net		—		126
Net cash used in investing activities		(18,067)		(13,879)
Cash flows from financing activities				
Proceeds from credit facility borrowings		7,000		—
Repayment of credit facility borrowings		(2,000)		(75)
Other, net		(30)		—
Net cash provided by (used in) financing activities		4,970		(75)
Net (decrease) increase in cash and cash equivalents		(3,629)		14,577
Cash and cash equivalents – beginning of period		6,761		11,955
Cash and cash equivalents – end of period	$	3,132	$	26,532
Supplemental disclosures:				
Cash paid for:				
Interest, net of amounts capitalized	$	348	$	594
Income taxes paid , net of (refunds)	$	—	$	(35)
Reorganization items, net	$	634	$	—
Non-cash investing and financing activities:				
Changes in accrued liabilities related to capital expenditures	$	2,262	$	(9,697)
Derivatives settled to reduce outstanding debt	$	—	$	22,860

See accompanying notes to condensed consolidated financial statements.

PENN VIRGINIA CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – unaudited
For the Quarterly Period Ended March 31, 2017
(in thousands, except per share amounts or where otherwise indicated)

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 are currently in the process of remediating the sites of our former wells in that region.

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 three months ended March 31, 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.

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

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.

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 service 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 2018.

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 May 5, 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 March 31, 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:

	March 31, 2017	December 31, 2016
Customers	$ 23,331	$ 20,489
Joint interest partners	16,024	7,238
Other [1]	1,693	3,789
	41,048	31,516
Less: Allowance for doubtful accounts	(2,381)	(2,421)
	$ 38,667	$ 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 three months ended March 31, 2017, one customer accounted for $31.2 million, or approximately 90%, of our consolidated product revenues. As of March 31, 2017, $20.2 million, or approximately 86%, of our consolidated accounts receivable from customers was related to this customer. For the three months ended March 31, 2016, two customers accounted for $26.5 million, or approximately 88%, of our consolidated product revenues. The revenues generated from these customers during the three months ended March 31, 2016 were $13.9 million and $12.6 million, or approximately 46%, and 42% 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 NYMEX Henry Hub gas and West Texas Intermediate crude oil 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.

In March 2016, we terminated two of our pre-petition derivative contracts for $22.9 million and the proceeds were used to reduce our amount outstanding under our pre-petition credit agreement (the “RBL”). 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 three months ended March 31, 2016.

On May 13, 2016, we entered into new commodity derivative contracts, pursuant to which we hedged a substantial portion of our future crude oil production through the end of 2019 at a weighted-average price of approximately $49.12 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 March 31, 2017:

	Instrument	Average Volume Per Day	Weighted Average Price		Fair Value	
			Floor/Swap	Ceiling	Asset	Liability
Crude Oil:		(barrels)	($/barrel)			
Second quarter 2017	Swaps	4,408	$ 48.62		$ —	$ 1,003
Third quarter 2017	Swaps	4,408	$ 48.62		—	1,286
Fourth quarter 2017	Swaps	4,408	$ 48.62		—	1,355
First quarter 2018	Swaps	3,476	$ 49.12		—	881
Second quarter 2018	Swaps	3,476	$ 49.12		—	838
Third quarter 2018	Swaps	3,476	$ 49.12		—	780
Fourth quarter 2018	Swaps	3,476	$ 49.12		—	718
First quarter 2019	Swaps	2,916	$ 49.90		—	359
Second quarter 2019	Swaps	2,916	$ 49.90		—	338
Third quarter 2019	Swaps	2,916	$ 49.90		—	329
Fourth quarter 2019	Swaps	2,916	$ 49.90		—	332
Settlements to be paid in subsequent period					—	142

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
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Derivative gains	$ 17,016	$ 4,492

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 losses (gains)” 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			
		March 31, 2017		December 31, 2016	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ —	$ 4,667	$ —	$ 12,932
Commodity contracts	Derivative assets/liabilities - noncurrent	—	3,694	—	14,437
		$ —	$ 8,361	$ —	$ 27,369

As of March 31, 2017, we reported a net commodity derivative liability of $8.4 million. The contracts associated with this position are with three counterparties, all of which are investment grade financial institutions. This concentration may impact our overall credit risk, either positively or negatively, 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:

	March 31, 2017	December 31, 2016
Oil and gas properties:		
Proved	$ 272,947	$ 251,083
Unproved	3,468	4,719
Total oil and gas properties	276,415	255,802
Other property and equipment	3,575	3,575
Total properties and equipment	279,990	259,377
Accumulated depreciation, depletion and amortization	(21,664)	(11,904)
	$ 258,326	$ 247,473

Unproved property costs of $3.5 million and $4.7 million have been excluded from amortization as of March 31, 2017 and December 31, 2016, respectively. We transferred $1.9 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 three months ended March 31, 2017. We capitalized internal costs of $0.6 million and interest of less than $0.1 million during the three months ended March 31, 2017 in accordance with our accounting policies. Average DD&A per BOE of proved oil and gas properties was $11.47 and $9.91 for the three months ended March 31, 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 provides for a $200 million revolving commitment and an initial borrowing base of $128 million. The Credit Facility also 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. As of December 31, 2016, the borrowing base was $128 million. In March 2017, we and the lenders under the Credit Facility began the process for the April 2017 redetermination but we have not yet finalized the borrowing base increase as of the date of this quarterly report. 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 $30 million and $25 million under the Credit Facility as of March 31, 2017 and December 31, 2016, respectively. We also had $0.8 million in letters of credit outstanding as of March 31, 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 March 31, 2017, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 3.915%. 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 March 31, 2017, we were in compliance with all of these covenants.

8. Income Taxes

We recognized a federal and state income tax expense for the three months ended March 31, 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 months ended March 31, 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 three month period ended March 31, 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 10 of whom were terminated in the the three months ended March 31, 2016. We incurred charges of $0.7 million in connection with this action and paid a total of $0.4 million in severance and termination benefits during the three months ended March 31, 2016. We recognized an immaterial credit adjustment to the remaining obligation of less than $0.1 million during the three months ended March 31, 2017. There were no payments under these obligations during the three months ended March 31, 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 $0.4 million in early termination charges during the three months ended March 31, 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 three months ended March 31, 2016, we paid a total of $0.5 million and recognized accretion expense of $0.2 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:

	March 31, 2017	December 31, 2016
Other current assets:		
Tubular inventory and well materials	$ 1,931	$ 2,125
Prepaid expenses	1,179	903
	$ 3,110	$ 3,028
Other assets:		
Deferred issuance costs of the Credit Facility	$ 2,597	$ 2,785
Other	2,579	2,544
	$ 5,176	$ 5,329
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 6,617	$ 9,825
Drilling costs	4,741	2,479
Royalties and revenue – related	29,839	26,116
Compensation – related	1,345	2,557
Interest	57	55
Reserve for bankruptcy claims	3,922	3,922
Other	4,603	4,743
	$ 51,124	$ 49,697
Other liabilities:		
Asset retirement obligations	$ 2,532	$ 2,459
Defined benefit pension obligations	998	1,025
Postretirement health care benefit obligations	506	488
Other	100	100
	$ 4,136	$ 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 March 31, 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:

	March 31, 2017			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Liabilities:				
Commodity derivative liabilities – current	$ (4,667)	$ —	$ (4,667)	$ —
Commodity derivative liabilities – noncurrent	(3,694)	—	(3,694)	—

	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 three months ended March 31, 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: $7.3 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 March 31, 2017, we had contractual commitments for two drilling rigs. The first rig is committed for the drilling of seven wells in the Eagle Ford based on a fixed daily rate. The second rig is subject to a six-month commitment which began in mid-March 2017. We have an approximate $2.7 million remaining obligation associated with this commitment.

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 March 31, 2017, we continue to maintain a $0.1 million reserve for a litigation matter. As of March 31, 2017, we also had AROs of approximately $2.7 million attributable to the plugging of abandoned wells.

13. Shareholders’ Equity

The following tables summarize the components of our shareholders ’ equity (deficit) and the changes therein as of and for three months ended March 31, 2017:

	As of December 31, 2016	Net Income	All Other Changes [1]	As of March 31, 2017
Common stock	150	—	—	150
Paid-in capital	190,621	—	835	191,456
Retained earnings (accumulated deficit)	(5,296)	28,407	—	23,111
Accumulated other comprehensive income	73	—	—	73
	$ 185,548	$ 28,407	$ 835	$ 214,790

[1] Includes equity-classified share-based compensation of $846.

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 254,397 shares of time-vested restricted stock units (“RSUs”) and 62,675 performance restricted stock units (“PRSUs”) had been granted as of March 31, 2017.

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

	Successor	Predecessor
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Equity-classified awards	$ 846	$ (602)
Liability-classified awards	—	(7)
	$ 846	$ (609)

In January 2017, we granted 146,834 RSUs to certain employees with a grant-date fair value of $51.71 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 senior 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 months ended March 31, 2017 and 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 months ended March 31, 2017 and 2016.

15. Interest Expense

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

	Successor	Predecessor
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Interest on borrowings and related fees	$ 390	$ 23,305
Amortization of debt issuance costs	188	1,269
Capitalized interest	(40)	(140)
	$ 538	$ 24,434

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
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Net income (loss)	$ 28,407	$ (33,473)
Less: Preferred stock dividends [1]	—	$ (3,152)
Net income (loss) attributable to common shareholders – basic and diluted	$ 28,407	$ (36,625)
Weighted-average shares – basic	14,992	85,941
Effect of dilutive securities [2]	134	—
Weighted-average shares – diluted	15,126	85,941

[1] Dividends attributable to our Series A 6% Convertible Perpetual Preferred Stock and Series B 6% Convertible Perpetual Preferred Stock (the "Series A and B Preferred Stock") were excluded from the computation of diluted loss per share for the three months ended March 31, 2016 , as their assumed conversion would have been anti-dilutive.

[2] The number of dilutive securities for the three months ended March 31, 2017, which is attributable to RSUs, was determined under the "treasury stock" method. The effect of PRSUs was anti-dilutive for the 2017 period. For the three months ended March 31, 2016 , approximately 27.6 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:

- potential adverse effects of the completed Chapter 11, or bankruptcy, proceedings on our liquidity, results of operations, brand, business prospects, ability to retain financing and other risks and uncertainties related to our emergence from bankruptcy;
- the ability to operate our business following 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;
- costs or results of any strategic alternatives;
- 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; 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 are currently in the process of remediating the sites of our former wells in that region.

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 our 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 facilitate our discussion herein, 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.

While crude oil prices have recovered somewhat from recent historic low levels of less than $30 per barrel, or Bbl, in February 2016 to approximately $55 per Bbl by the end of 2016 and down to the mid-$40 range per Bbl as of May 5, 2017, they remain depressed due to domestic and global supply and demand factors compared to the period of 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.

The following summarizes our key operating and financial highlights for the three months ended March 31, 2017 with comparison to the corresponding period of 2016, where applicable. These highlights are addressed in further detail in the discussions for *Results of Operations* and *Financial Condition* that follow:

- Production declined approximately 39 percent to 855 thousand barrels of oil equivalent, or MBOE, due primarily to the effects of the suspension of our drilling program in February 2016 through November 2016 as well as natural declines.
- Product revenues increased approximately 15 percent to $34.7 million due to higher pricing for crude oil, NGLs and natural gas despite the aforementioned decline in production volume.
- Crude oil production and revenues maintained consistent levels of approximately 70 percent and 86 percent, respectively, of our consolidated totals. Eagle Ford production continues to represent over 90 percent of our total production.
- Our production and lifting costs declined on an absolute basis, but increased on a per unit basis due primarily to the decline in production volume and higher surface repair and maintenance costs.
- Production and severance taxes increased on an absolute and per unit basis due to higher pricing in the 2017 period and the recognition of certain severance tax refunds in the 2016 period.
- General and administrative expenses declined due primarily to: (i) strategic and financial advisory costs incurred in the 2016 Predecessor period in advance of our bankruptcy filing, (ii) a substantial reduction in the size of our workforce, (iii) the closure of our former headquarters office in Radnor, Pennsylvania and the centralization of our corporate

headquarters to a smaller office location in Houston, Texas and (iv) termination and severance costs incurred in the 2016 Predecessor period partially offset by higher share-based compensation costs attributable to grants of awards under the 2016 management incentive plan that was put in place after our emergence from bankruptcy.

- We incurred exploration costs of $1.3 million during the 2016 Predecessor period while we applied the successful efforts method of accounting for oil and gas properties. Similar costs are now capitalized under the full cost method. Our depletion, depreciation and amortization costs, or DD&A, increased due primarily to lower production, but the rates are not comparable as they are derived from different cost and reserve bases as well as different methods (full cost vs. successful efforts).
- Our operating income increased $24.4 million due to the combined effect of the product revenue and operating cost highlights discussed above.
- Our increased capital expenditures reflect the restart of our drilling program in November 2016 with one drilling rig following a suspension that began in February 2016 and continued throughout the period during which we were involved in bankruptcy proceedings. We further expanded the program at the end of the first quarter of 2017 with an additional drilling rig.
- We drilled six gross (2.4 net) Eagle Ford wells during the three months ended March 31, 2017.
- We ended the 2017 quarterly period with $30 million of borrowings outstanding under our credit agreement, or Credit Facility.

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

	Successor		Predecessor	
	Three Months Ended March 31, 2017		Three Months Ended March 31, 2016	
Total production (MBOE)		855		1,394
Average daily production (BOEPD)		9,495		15,323
Crude oil production (MBbl)		608		973
Crude oil production as a percent of total		71%		70%
Product revenues	$	34,718	$	30,321
Crude oil revenues	$	30,073	$	25,966
Crude oil revenues as a percent of total		87%		86%
Realized prices:				
Crude oil ($ per Bbl) [1]	$	49.47	$	26.69
NGLs ($ per Bbl)	$	19.34	$	9.14
Natural gas ($ per Mcf)	$	3.06	$	1.93
Aggregate ($ per BOE)	$	40.63	$	21.75
Production and lifting costs ($/BOE)				
Lease operating	$	5.84	$	4.44
Gathering, processing and transportation	$	2.98	$	2.74
Production and ad valorem taxes ($ per BOE)	$	2.31	$	0.54
General and administrative ($ per BOE) [2]	$	4.83	$	12.27
Depreciation, depletion and amortization ($ per BOE) [3]	$	11.47	$	9.91
Cash provided by operating activities [4]	$	9,468	$	28,531
Cash paid for capital expenditures	$	18,067	$	14,005
Cash and cash equivalents at end of period	$	3,132	$	26,532
Debt outstanding at end of period	$	30,000	$	1,222,065
Credit available under credit facility at end of period [5]	$	97,233	$	—
Net development wells drilled and completed		2.4		2.5

[1] Crude oil prices adjusted for derivatives were $46.19 and $58.10 per Bbl for the Successor and Predecessor periods, respectively.

[2] Includes combined amounts of $0.97 and $8.04 per BOE 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,* " for the Successor and Predecessor periods, respectively.

[3] Determined using the full cost method for the Successor period and the successful efforts method for the Predecessor period.

[4] Includes cash paid for derivative settlements of $2.0 million for the Successor period and cash received for derivative settlements of $30.6 million for the Predecessor period.

[5] As of March 31, 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 first quarter of 2017 was 855 thousand barrels of oil equivalent, or MBOE, or 9,495 barrels of oil equivalent per day, or BOEPD, with approximately 71 percent, or 608 MBOE, of production from crude oil, 14 percent from NGLs and 15 percent from natural gas. Production from our Eagle Ford operations during this period was 770 MBOE or 8,561 BOEPD. Approximately 77 percent of our Eagle Ford production for the period was from crude oil, 12 percent was from NGLs and 11 percent was from natural gas. Production from our Eagle Ford operations was approximately 90 percent of total Company production during the period.

Our Eagle Ford production for the quarter reflected approximately two months of production from the three-well Sable pad, and one month of production from the three-well Axis pad. In April 2017, we turned production from the four-well Kudu pad, located in the northern portion of our acreage, to sales. We have an average working interest of 43.7 percent in each of the Kudu wells. In March 2017, production from the three-well Axis pad was turned to sales. The Lager 3H, in which we have 41.2 percent working interest and is located in the southeastern portion of our acreage, was completed in April and is flowing back.

Capital expenditures for 2017 are expected to total between $120 and $140 million with approximately 90 percent of capital being directed to drilling and completions in the Eagle Ford. Our capital plan provides for drilling 41 to 44 gross wells (19 to 22 net wells) under a two-rig program, with 31 to 34 gross wells (16 to 19 net wells) turned to sales. We plan to fund our 2017 capital expenditures with cash from operating activities and borrowings under the Credit Facility.

We added and/or extended approximately 1,700 net acres to our core leasehold position in the volatile window of the lower Eagle Ford bringing our core net acreage position to approximately 56,000 as of May 5, 2017. Approximately 93 percent of our core acreage is held by production. We operate 311 gross wells and have working interests in 42 gross outside-operated wells in the Eagle Ford as of May 5, 2017.

Commodity Hedging Program

We have hedged a substantial portion of our future crude oil production through the end of 2019. Our weighted-average hedge prices are approximately $48.62 per barrel for the remainder of 2017, $49.12 per barrel for 2018 and $49.90 per barrel for 2019. We are currently unhedged with respect to NGL and natural gas production.

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 $128 million. In March 2017, we and the lenders under the Credit Facility began the process for the redetermination but we have not yet finalized the borrowing base increase as of the date of this report. As of May 5, 2017, we had outstanding borrowings and letters of credit of $35.0 million and $0.8 million, respectively, resulting in $92.2 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 hedged a substantial portion of our future crude oil production through the end of 2019. Our weighted-average hedge prices are $48.62 per barrel for the remainder of 2017, $49.12 per barrel for 2018 and $49.90 per barrel for 2019. Our natural gas hedges expired in 2015 and we currently are and expect to remain unhedged with respect to natural gas as well as NGL production.

Capital Resources

Under our business plan, we currently anticipate capital expenditures to total between $120 million and $140 million for 2017, with approximately 90 percent of capital being directed to drilling and completions on our Eagle Ford acreage. 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. Our 2017 capital expenditure budget does not allocate any funds for acquisitions. For a detailed analysis of our historical capital expenditures, see "*Cash Flows.*"

Cash on Hand and Cash From Operating Activities. As of May 5, 2017, we had approximately $5 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. Since that time we have paid down $40.4 million, net of new borrowings through May 5, 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 March 31, 2017	$ 26,900	$ 30,000	3.7920%

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. Form 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.
	Three Months Ended	Three Months Ended	2016
	March 31,	March 31,	Favorable
	2017	2016	(Unfavorable)
Cash flows from operating activities			
Operating cash flows, net of working capital changes	$ 12,442	$ 11,770	$ 672
Crude oil derivative settlements (paid) received, net	(1,992)	30,559	(32,551)
Interest payments, net of amounts capitalized	(348)	(594)	246
Income taxes received (paid)	—	35	(35)
Strategic, financial and bankruptcy-related advisory fees and costs paid	(634)	(12,350)	11,716
Restructuring and exit costs paid	—	(889)	889
Net cash provided by operating activities	9,468	28,531	(19,063)
Cash flows from investing activities			
Capital expenditures	(18,067)	(14,005)	(4,062)
Proceeds from sales of assets, net	—	126	(126)
Net cash used in investing activities	(18,067)	(13,879)	(4,188)
Cash flows from financing activities			
Proceeds (repayments) from credit facility borrowings, net	5,000	(75)	5,075
Other, net	(30)	—	(30)
Net cash provided by (used in) financing activities	4,970	(75)	5,045
Net (decrease) increase in cash and cash equivalents	$ (3,629)	$ 14,577	$ (18,206)

Cash Flows from Operating Activities. We received substantially lower settlements from derivatives during the 2017 Successor period compared to the 2016 Predecessor period due primarily to: (i) lower spreads between hedged and realized West Texas Intermediate, or WTI, crude oil prices on our post-petition derivatives, (ii) lower overall crude oil volumes hedged and (iii) the early termination of certain pre-petition derivative contracts, most of the proceeds from which were used to pay down borrowings under the RBL. In addition, we experienced higher working capital utilization in the 2017 Successor period as a result of the restart of our drilling program, which had been suspended in February 2016. This overall decline in operating cash flows was partially offset by the effect of: (i) substantially higher payments in 2016 for professional fees and other costs associated with our consideration of strategic financing alternatives and in advance of our bankruptcy petition, (ii) payments for termination benefits and other exit activities in the 2016 Predecessor period, (iii) 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 2016 Predecessor period and (iii) higher overall product revenue receipts in the 2017 Successor period. While aggregate average commodity prices increased during the Successor period in 2017 compared to the Predecessor period in 2016, receipts from product revenues were somewhat offset by the effects of lower production due primarily to: (i) the suspension of our Eagle Ford drilling program in February 2016 and (ii) natural production declines.

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

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

	Successor	Predecessor
	Three Months Ended	Three Months Ended
	March 31,	March 31,
	2017	2016
Drilling and completion	$ 19,640	$ 4,008
Lease acquisitions and other land-related costs	714	205
Pipeline, gathering facilities and other equipment	(455)	318
Geological, geophysical (seismic) and delay rental costs	186	(19)
	$ 20,085	$ 4,512

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
	Three Months Ended	Three Months Ended
	March 31,	March 31,
	2017	2016
Total capital program costs (from above)	$ 20,085	$ 4,512
(Increase) decrease in accrued capitalized costs	(2,262)	9,697
Less:		
Exploration costs charged to operations [1]:		
Geological, geophysical (seismic) and delay rental costs	—	19
Transfers from tubular inventory and well materials	(331)	(505)
Add:		
Tubular inventory and well materials purchased in advance of drilling	72	142
Capitalized internal labor [1]	463	—
Capitalized interest	40	140
Total cash paid for capital expenditures	$ 18,067	$ 14,005

[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 $7 million and repayments of $2 million under the Credit Facility while the 2016 Predecessor period includes a repayment of $0.1 million under the RBL.

Capitalization

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

	March 31, 2017	December 31, 2016
Credit Facility borrowings	$ 30,000	$ 25,000
Shareholders' equity	214,790	185,548
	$ 244,790	$ 210,548
Debt as a % of total capitalization	12%	12%

Credit Facility. The Credit Facility provides for a $200 million revolving commitment. 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. As discussed above, a borrowing base redetermination is in process as of the date of this quarterly report. 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 March 31, 2017, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 3.915%. 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 March 31, 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 generally 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), 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 months ended March 31, 2017 and 2016 without regard to the concept of a Successor and Predecessor facilitates 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 March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
		(Total volume)			(Volume per day)	
Crude oil (MBbl & BOPD)	608	973	(365)	6,755	10,691	(3,936)
NGLs (MBbl and BOPD)	119	214	(95)	1,322	2,347	(1,025)
Natural gas (MMcf and MMcfpd)	765	1,247	(482)	9	14	(5)
Total (MBOE and BOEPD)	855	1,394	(540)	9,495	15,323	(5,828)
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
		(MBOE)			(BOE per day)	
South Texas	770	1,291	(521)	8,561	14,188	(5,627)
Mid-Continent and other [1]	84	103	(19)	934	1,134	(200)
	855	1,394	(540)	9,495	15,323	(5,828)

[1] Includes total production and average daily production of approximately 5 MBOE (53 BOEPD) attributable to our currently inactive Marcellus Shale wells for the three months ended March 31, 2016.

Total production decreased during the Successor period in 2017 when compared to the 2016 Predecessor period 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 71 percent of total production during the Successor period in 2017 was attributable to oil when compared to approximately 70 percent during the Predecessor period in 2016. Our Eagle Ford production represented 90 percent of our total production during the Successor period in 2017 compared to approximately 93 percent from this region during the Predecessor period in 2016. During the Successor period in 2017, we turned six gross Eagle Ford wells to sales compared to five gross wells during the 2016 Predecessor 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 March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
					($ per unit of volume)	
Crude oil	$ 30,073	$ 25,966	$ 4,107	$ 49.47	$ 26.69	$ 22.78
NGLs	2,302	1,953	349	$ 19.34	$ 9.14	$ 10.20
Natural gas	2,343	2,402	(59)	$ 3.06	$ 1.93	$ 1.13
Total	$ 34,718	$ 30,321	$ 4,397	$ 40.63	$ 21.75	$ 18.88
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
					($ per BOE)	
South Texas	$ 32,687	$ 28,755	$ 3,932	$ 42.42	$ 22.27	$ 20.15
Mid-Continent and other [1]	2,031	1,566	465	$ 24.16	$ 15.17	$ 8.99
	$ 34,718	$ 30,321	$ 4,397	$ 40.63	$ 21.75	$ 18.88

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

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

	Three Months Ended March 31, 2017 vs. 2016 Revenue Variance Due to		
	Volume	Price	Total
Crude oil	$ (9,738)	$ 13,845	4,107
NGLs	(865)	1,214	349
Natural gas	(928)	869	(59)
	$ (11,531)	$ 15,928	$ 4,397

Our product revenues increased during the Successor period in 2017 as compared to the Predecessor 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 87 percent and 86 percent and total Eagle Ford revenues were approximately 94 percent and 95 percent of total revenues for the 2017 Successor period and the 2016 Predecessor period, respectively.

Effects of Derivatives

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

	Successor	Predecessor	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Crude oil revenues as reported	$ 30,073	$ 25,966	$ 4,107
Derivative settlements, net	(1,992)	30,559	(32,551)
	$ 28,081	$ 56,525	$ (28,444)
Crude oil prices per Bbl	$ 49.47	$ 26.69	$ 22.78
Derivative settlements per Bbl	(3.28)	31.41	(34.69)
	$ 46.19	$ 58.10	$ (11.91)

Gain (Loss) on the Sales of Assets

There were insignificant gains and losses recognized during the 2017 Successor period and 2016 Predecessor period attributable to tubular inventory and well materials. The $0.2 million net loss during the 2016 Predecessor period was partially offset by 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, which includes gathering, transportation, marketing, compression, water supply and disposal fees that we charge to third parties, net of marketing and related expenses as well as accretion, during the Predecessor period, of our unused firm transportation obligation, increased during the Successor period in 2017 from the Predecessor period in 2016 due primarily to higher water supply and disposal fees in the South Texas region as drilling in this region resumed. The 2016 Predecessor period includes $0.2 million of accretion attributable to the unused firm transportation while there is no such charge in the 2017 Successor period as this 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	Predecessor	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Lease operating	$ 4,989	$ 6,192	$ 1,203
Per unit of production ($/BOE)	5.84	4.44	(1.40)

LOE decreased during the 2017 Successor period on an absolute basis when compared to the 2016 Predecessor period due primarily to lower overall production, cost containment efforts that we implemented throughout 2016 and into 2017 and lower industry-wide pricing for certain oilfield products and services. The per unit LOE cost increased in the 2017 Successor period 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 repair and maintenance costs.

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	Predecessor	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Gathering, processing and transportation	$ 2,551	$ 3,818	$ 1,267
Per unit of production ($/BOE)	$ 2.98	$ 2.74	$ (0.24)

GPT decreased during the 2017 Successor period when compared to the 2016 Predecessor period due primarily to substantially lower production volumes as discussed above. We also incurred costs in the 2016 Predecessor period for unused firm transportation services in the Marcellus prior to our termination of operations in that region. There were no such costs incurred in the 2017 Successor period as the underlying contract was rejected in our bankruptcy proceedings. Per unit rates increased during the 2017 Successor period as oil gathering services commenced by Republic Midstream LLC in April 2016.

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	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Production and ad valorem taxes			
Production/severance taxes	$ 1,655	$ 196	$ (1,459)
Ad valorem taxes	324	557	233
	$ 1,979	$ 753	$ (1,226)
Per unit production ($/BOE)	$ 2.31	$ 0.54	$ (1.77)
Production/severance tax rate as a percent of product revenue	4.8%	0.6%	

Production taxes increased on both an absolute and per unit basis during the Successor period in 2017 when compared to the Predecessor period in 2016 due primarily to the recognition of certain severance tax refunds from Oklahoma in the 2016 Predecessor period that were attributable to prior periods, as well as higher commodity sales prices despite a decline in production volume in the 2017 Successor period. 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	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Primary general and administrative expenses	$ 3,301	$ 5,900	$ 2,599
Share-based compensation (liability-classified)	—	(7)	(7)
Share-based compensation (equity-classified)	846	(602)	(1,448)
Significant special charges:			
Strategic and financial advisory costs	—	11,063	11,063
Restructuring expenses	(20)	748	768
Total general and administrative expenses	$ 4,127	$ 17,102	$ 12,975
Per unit of production ($/BOE)	$ 4.83	$ 12.27	$ 7.44
Per unit of production excluding all share-based compensation and other significant special charges identified above ($/BOE)	$ 3.86	$ 4.23	$ 0.37

Our primary G&A expenses decreased on an absolute and per unit basis during the 2017 Successor period compared to the 2016 Predecessor period. The decrease is due primarily to the effects of: (i) lower payroll and benefits attributable to lower employee headcount, (ii) the relocation of our headquarters from Radnor, Pennsylvania to Houston, Texas and related move to a smaller office location, (iii) reduced travel and entertainment and (iv) 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 Predecessor period was attributable to our former performance-based restricted stock units, or PBRSUs, and represents mark-to-market charges 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 Predecessor period 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 Successor period in 2017 are attributable to the grants of Successor time-vested restricted stock units, or RSUs, in the fourth quarter of 2016 and the first quarter of 2017 as well as Successor 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 Predecessor period reflects forfeitures of the Predecessor's stock options. All of our equity-classified share-based compensation represents non-cash expenses.

During the Predecessor period 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 incurred related termination and severance benefit costs during the Predecessor period.

Exploration

While applying the successful efforts method of accounting to our oil and gas properties during the Predecessor period in 2016, we incurred costs which were charged to operations in accordance with the successful efforts method. In the Successor period, 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 period presented:

	Successor	Predecessor	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Unproved leasehold amortization	$ —	$ 856	$ 856
Drilling rig termination charges	—	490	490
Geological and geophysical costs	—	33	33
Other, primarily delay rentals	—	(52)	(52)
	$ —	$ 1,327	$ 1,327

In addition to normal exploration costs associated with the successful efforts method, we incurred early termination charges in connection with the release of a drilling rig in the Eagle Ford in the 2016 Predecessor period.

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 period in 2017 as compared to the Predecessor period in 2016. The following table sets forth total and per unit costs for DD&A:

	Successor	Predecessor	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
DD&A expense	$ 9,810	$ 13,812	$ 4,002
DD&A Rate ($/BOE)	$ 11.47	$ 9.91	$ (1.56)

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 Successor period in 2017 when compared to the Predecessor period 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	Predecessor	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Interest on borrowings and related fees	$ 390	$ 23,305	$ 22,915
Amortization of debt issuance costs	188	1,269	1,081
Capitalized interest	(40)	(140)	(100)
	$ 538	$ 24,434	$ 23,896

Interest expense during the 2017 Successor period is exclusively attributable to the Credit Facility. Interest expense during the 2016 Predecessor period 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. The overall decrease is due to substantially higher outstanding indebtedness during the 2016 Predecessor period.

Derivatives

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

	Successor	Predecessor	
	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016 Favorable (Unfavorable)
Crude oil derivative gains	$ 17,016	$ 4,492	$ 12,524
Natural gas derivative gains (losses)	—	—	—
	$ 17,016	$ 4,492	$ 12,524

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 $2.0 million in the 2017 Successor period as compared to the receipt of $30.6 million of cash settlements for crude oil derivatives during the Predecessor period in 2016. The decline in total cash settlements is attributable to: (i) lower spreads between hedge and realized WTI prices on our post-petition derivatives, (ii) lower overall crude oil volumes hedged and (iii) the early termination of certain pre-petition derivative contracts, most of the proceeds from which were directly provided to the RBL lenders to pay down borrowings under the RBL, prior to our bankruptcy filing.

Other, net

In the Predecessor period 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.

Income Taxes

We recognized a federal and state income tax expense for the Successor period 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 months ended March 31, 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 three month period ended March 31, 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 March 31, 2017, we had no off-balance sheet arrangements.

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.

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 service 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 2018.

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 March 31, 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 March 31, 2017, such disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

During the three months ended March 31, 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***

There have been no material developments with respect to material legal proceedings disclosed in Part I, Item 3 of our Annual report on Form 10-K for the year ended December 31, 2016.

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 6. ***Exhibits***

(10.1)	Amendment No. 1 to Credit Agreement dated as of March 10, 2017 among Penn Virginia Holding Corp., Penn Virginia Corporation, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1.1 to Registrant's Registration Statement on Form S-3/A (Amendment No. 2) filed on May 2, 2017).
(10.2)	Amendment No. 1 to the Second Amended and Restated Construction and Field Gathering Agreement dated as of April 13, 2017 but effective August 1, 2016, by and between Republic Midstream, LLC and Penn Virginia Oil & Gas, L.P. (incorporated by reference to Exhibit 10.4.1 to the Registrant's Registration Statement on Form S-3/A (Amendment No. 2) filed on May 2, 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

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

May 10, 2017

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

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: May 10, 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: May 10, 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 three months ended March 31, 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: May 10, 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 three months ended March 31, 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: May 10, 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.