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

FORM 10-K

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

For the fiscal year ended December 31, 2018

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)

16285 Park Ten Place, Suite 500
Houston, TX 77084
(Address of principal executive offices)
Registrant's telephone number, including area code: **(713) 722-6500**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, $0.01 Par Value	**NASDAQ Global Select Market**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or 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	☐	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 Act). Yes ☐ No ☒

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was $1,086,140,215 as of June 29, 2018 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the NASDAQ Global Select Market.

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

As of February 22, 2019, 15,105,251 shares of common stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information called for in Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference to the registrant's definitive proxy statement or will be included in an amendment to this Annual Report on Form 10-K.

PENN VIRGINIA CORPORATION
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2018

Table of Contents

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. We use words such as "anticipate," "guidance," "assumptions," "projects," "estimates," "expects," "continues," "intends," "plans," "believes," "forecasts," "future," "potential," "may," "possible," "could" and variations of such words or similar expressions to identify forward-looking statements. 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:

- all of the risks and uncertainty related to our announced merger with Denbury Resources Inc., including the risk that the conditions to the closing of the transaction are not satisfied and the additional risks discussed in Part I, Item 1A of this report;
- risks related to completed acquisitions, including our ability to realize their expected benefits;
- our ability to satisfy our short-term and long-term liquidity needs, including our ability 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;
- 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, materials, supplies and services at reasonable costs;
- our ability to renew or replace expiring contracts on acceptable terms;
- our ability to obtain adequate pipeline transportation capacity or other transportation 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 that estimated in our proved oil and gas reserves;
- use of new techniques in our development, including choke management and longer laterals;
- drilling and operating risks;
- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements with other parties and counterparty risk related to the ability of these parties to meet their future obligations;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- our reliance on a limited number of customers and a particular region for substantially all of our revenues and production;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties relating to general domestic and international economic and political conditions;
- the impact and costs associated with litigation or other legal matters; and

- other factors set forth in our periodic filings with the Securities and Exchange Commission, or SEC, including the risks set forth in Part I, Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2018.

Additional information concerning these and other factors can be found in our press releases and public filings with the SEC. 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.

Glossary of Certain Industry Terminology

The following abbreviations, terms and definitions are commonly used in the oil and gas industry and are used within this Annual Report on Form 10-K.

Bbl. A standard barrel of 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

BOE. One barrel of oil equivalent with six thousand cubic feet of natural gas converted to one barrel of crude oil based on the estimated relative energy content.

BOEPD. Barrels of oil equivalent per day.

Borrowing base. The value assigned to a collection of borrower's assets used by lenders to determine an initial and/or continuing amount for loans. In the case of oil and gas exploration and development companies, the borrowing base is generally based on proved developed reserves.

Completion. A process of treating a drilled well, including hydraulic fracturing among other stimulation processes, followed by the installation of permanent equipment for the production of oil or gas.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface temperature and pressure.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing either oil or gas in sufficient commercial quantities to justify completion of the well.

Drilling carry. A working interest that will be carried through the drilling and completion of a well.

EBITDAX. A measure of profitability utilized in the oil and gas industry representing earnings before interest, income taxes, depreciation, depletion, amortization and exploration expenses. EBITDAX is not a defined term or measure in generally accepted accounting principles, or GAAP (see below).

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.

EUR. Estimated ultimate reserves, the sum of reserves remaining as of a given date and cumulative production as of that date.

GAAP. Accounting principles generally accepted in the Unites States of America.

Gas lift. A method of artificial lift that uses an external source of high-pressure gas for supplementing formation gas for lifting the well fluids.

Gross acre or well. An acre or well in which a working interest is owned.

HBP. Held by production is a provision in an oil and gas or mineral lease that perpetuates the leaseholder's right to operate the property as long as the property produces a minimum paying quantity of oil or gas.

Henry Hub. The Erath, Louisiana settlement point price for natural gas.

IP. Initial production, a measurement of a well's production at the outset.

LIBOR. London Interbank Offered Rate.

LLS. Light Louisiana Sweet, a crude oil pricing index reference.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units, a measure of energy content.

MMcf. One million cubic feet of natural gas.

Nasdaq. The NASDAQ Global Select Market.

Net acre or well. The number of gross acres or wells multiplied by the owned working interest in such gross acres or wells.

NGL. Natural gas liquid.

NYMEX. New York Mercantile Exchange.

Operator. The entity responsible for the exploration and/or production of a lease or well.

Play. A geological formation with potential oil and gas reserves.

Productive wells. Wells that are not dry holes.

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves. When probabilistic methods are used, there should be at least a 10 percent probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When probabilistic methods are used, there should be at least a 50 percent probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Proved reserves. Those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved developed reserves. Proved reserves that can be expected to be recovered: (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled.

PV10. A non-GAAP measure representing the present value of estimated future oil and gas revenues, net of estimated direct costs, discounted at an annual discount rate of 10%. PV10 is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for any GAAP measure. PV10 does not purport to represent the fair value of oil and gas properties.

Reservoir. A porous and permeable underground formation containing a natural accumulation of hydrocarbons that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Revenue interest. An economic interest in production of hydrocarbons from a specified property.

Royalty interest. An interest in the production of a well entitling the owner to a share of production generally free of the costs of exploration, development and production.

SEC. United States Securities and Exchange Commission.

Service well. A well drilled or completed for the purpose of supporting production in an existing field.

Standardized measure. The present value, discounted at 10% per year, of estimated future cash inflows from the production of proved reserves, computed by applying prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), reduced by estimated future development and production costs, computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year (including the settlement of asset retirement obligations), based on year-end costs and assuming continuation of existing economic conditions, further reduced by estimated future income tax expenses, computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the proved oil and gas reserves, less the tax basis of the properties involved and giving effect to the tax deductions and tax credits and allowances relating to the proved oil and gas reserves.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production.

Unconventional. Generally refers to hydrocarbon reservoirs that lack discrete boundaries that typically define conventional reservoirs. Examples include shales, tight sands or coal beds.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas, regardless of whether such acreage contains proved reserves. Under appropriate circumstances, undeveloped acreage may not be subject to expiration if properly held by production, as that term is defined above.

WTI. West Texas Intermediate, a crude oil pricing index reference.

Working interest. A cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease.

Part I

Item 1 Business

Unless the context requires otherwise, references to the "Company," "Penn Virginia," "we," "us" or "our" in this Annual Report on Form 10-K refer to Penn Virginia Corporation and its subsidiaries.

Description of Business

We are an independent oil and gas company engaged in the onshore exploration, development and production of crude oil, 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 Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

We were incorporated in the Commonwealth of Virginia in 1882. Our common stock is publicly traded on the Nasdaq under the symbol "PVAC." Our headquarters and corporate office is located in Houston, Texas. We also have a field operations office near our Eagle Ford assets in South Texas.

We operate in and report our financial results and disclosures as one segment, which is the exploration, development and production of crude oil, NGLs and natural gas.

Current Operations

We lease a highly contiguous position of approximately 84,200 net acres (as of December 31, 2018) in the core liquids-rich area or "volatile oil window" of the Eagle Ford in Gonzales, Lavaca, Fayette and Dewitt Counties in Texas, which we believe contains a substantial number of drilling locations that will support a multi-year drilling inventory.

In 2018, our total production was comprised of 76 percent crude oil, 13 percent NGLs and 11 percent natural gas. Crude oil accounted for 92 percent of our product revenues. We generally sell our crude oil, NGL and natural gas products using short-term floating price physical and spot market contracts.

As of December 31, 2018, our total proved reserves were approximately 123 MMBOE, of which38 percent were proved developed reserves and 73 percent were crude oil. As of December 31, 2018, we had 460 gross (377.5 net) productive wells, approximately 97 percent of which we operate, and owned approximately 98,200 gross (84,200 net) acres of leasehold and royalty interests, approximately 9 percent of which were undeveloped. Approximately 92 percent of our acreage is HBP and includes a substantial number of undrilled locations. During 2018, we drilled and completed 53 gross (45.5 net) wells, all in the Eagle Ford. For a more detailed discussion of our production, reserves, drilling activities, wells and acreage, see Part I, Item 2, "Properties."

On October 28, 2018, Denbury Resources Inc., or Denbury, and Penn Virginia announced that they entered into a definitive merger agreement, or the Merger Agreement, pursuant to which Denbury will acquire Penn Virginia, or the Merger. The consideration to be paid to Penn Virginia shareholders will consist of 12.4 shares of Denbury common stock and $25.86 of cash for each share of Penn Virginia common stock. Penn Virginia shareholders will be permitted to elect to receive either all cash, all stock or a mix of stock and cash, in each case subject to proration, which will result in the aggregate issuance by Denbury of approximately 191.667 million Denbury shares and payment by Denbury of $400 million in cash. The transaction was unanimously approved by the board of directors of each company, and certain Penn Virginia shareholders holding approximately 15 percent of the outstanding shares signed voting agreements to vote "for" the transaction. The transaction is subject to the approval by the holders of more than two-thirds of the outstanding Company common shares, the approval by the holders of a majority of the outstanding Denbury common shares of an amendment to the certificate of incorporation to increase the number of authorized Denbury common shares, the approval of the issuance of Denbury common shares in the Merger by the holders of a majority of the Denbury common shares represented in person or by proxy at a meeting of Denbury shareholders held to vote on such matter and other customary closing conditions. The special meeting of shareholders to approve the merger is anticipated in April 2019 and closing is anticipated soon thereafter, subject to shareholder approval and certain other conditions. The Merger Agreement contains certain termination rights for both Denbury and the Company, including if the Merger is not consummated by April 30, 2019, and requires Penn Virginia to pay a $45 million termination fee in certain circumstances.

On July 31, 2018, we sold all of our remaining Mid-Continent oil and gas properties, located primarily in Oklahoma in the Granite Wash. We realized net proceeds of $5.7 million in connection with the sale and utilized those funds in our Eagle Ford development program. Subsequent to the sale, our operations are exclusively focused in the Eagle Ford in South Texas.

On March 1, 2018, we completed the acquisition of certain oil and gas assets from Hunt Oil Company, or Hunt, including oil and gas leases covering approximately 9,700 net acres located primarily in Gonzalez and Lavaca Counties, Texas. For a more detailed discussion of this acquisition, see "*Key Developments*" included in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 5 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Emergence from Bankruptcy Proceedings and Fresh Start Accounting

On May 12, 2016, or the Petition Date, we and eight of our subsidiaries, or the Chapter 11 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, or the Bankruptcy Code, in the United States Bankruptcy Court for the Eastern District of Virginia, or the Bankruptcy Court.

On August 11, 2016, or the Confirmation Date, the Bankruptcy Court confirmed our Second Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and its Debtor Affiliates, or the Plan, and we subsequently emerged from bankruptcy on September 12, 2016, or the Emergence Date. On November 20, 2018, the Bankruptcy Court issued a final decree to close the case.

On the Emergence Date, we adopted and applied the relevant guidance with respect to the accounting and financial reporting for entities that have emerged from bankruptcy proceedings, or Fresh Start Accounting. The adoption of Fresh Start Accounting resulted in a new reporting entity, the Successor, for financial reporting purposes. To facilitate our discussion and analysis of our properties, 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. For a more detailed discussion of our bankruptcy proceedings, our emergence from bankruptcy and Fresh Start Accounting, see Note 4 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Key Contractual Arrangements

In the ordinary course of operating our business, we enter into a number of key contracts for services that are critical with respect to our ability to develop, produce and bring our production to market. The following is a summary of our most significant contractual arrangements.

Oil gathering and transportation service contracts. We have long-term agreements that provide us with gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production through 2041 as well as volume capacity support for certain downstream interstate pipeline transportation.

Natural gas service contracts. We have an agreement that provides us with gas lift, gathering, compression and short-haul transportation services for a substantial portion of our natural gas production until 2039.

Natural gas processing contracts. We have two agreements that provide us with services to process our wet gas production into NGL products and dry, or residue, gas. These agreements are evergreen in term with either party having the right to terminate with 30-days' notice to the counterparty.

Drilling and Completion. From time to time we enter into drilling, completion and materials contracts in the ordinary course of business to ensure availability of rigs, frac crews and materials to satisfy our development program. As of December 31, 2018, there were no drilling, completion or materials agreements with terms that extended beyond one year.

Major Customers

We sell a significant portion of our oil and gas production to a relatively small number of customers. For the year ended December 31, 2018, approximately 69 percent of our consolidated product revenues were attributable to three customers: Phillips 66 Company; BP Products North America Inc. and Shell Trading (US) Company.

Seasonality

Our sales volumes of oil and gas are dependent upon the number of producing wells and, therefore, are not seasonal by nature. We do not believe that the pricing of our crude oil and NGL production is subject to any meaningful seasonal effects. Historically, the pricing of natural gas is seasonal, typically with higher pricing in the winter months.

Competition

The oil and gas industry is very competitive, and we compete with a substantial number of other companies, many of which are large, well-established and have greater financial and operational resources than we do. Some of our competitors not only engage in the acquisition, exploration, development and production of oil and gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. In addition, the oil and gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers. Competition is particularly intense in the acquisition of prospective oil and gas properties. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. We also compete with other oil and gas companies to secure drilling rigs, frac fleets, sand and other equipment and materials necessary for the drilling and completion of wells and in the recruiting and retaining of qualified personnel. Such materials, equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. Many of our larger competitors may have a competitive advantage when responding to commodity price volatility and overall industry cycles.

Government Regulation and Environmental Matters

Our operations are subject to extensive federal, state and local laws and regulations that govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require notice to stakeholders of proposed and ongoing operations;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities for failure to comply. Violations and liabilities with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and cash flows. In certain instances, citizens or citizen groups also have the ability to bring legal proceedings against us if we are not in compliance with environmental laws or to challenge our ability to receive environmental permits that we need to operate. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2018, we have recorded asset retirement obligations of $4.3 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general.

In addition, the United States Environmental Protection Agency, or the EPA, has designated energy extraction as one of six national enforcement initiatives, and has indicated that the agency will direct resources towards addressing incidences of noncompliance from natural gas extraction and production activities. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition, results of operations or cash flows. Nevertheless, changes in existing environmental laws or regulations or the adoption of new environmental laws or regulations, including any significant limitation on the use of hydraulic fracturing, could have the potential to adversely affect our financial condition, results of operations and cash flows. Federal, state or local administrative decisions, developments in the federal or state court systems or other governmental or judicial actions may influence the interpretation or enforcement of environmental laws and regulations and may thereby increase compliance costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

The following is a summary of the significant environmental laws to which our business operations are subject.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, is also known as the "Superfund" law. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on parties that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Such "responsible parties" may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease properties that have been used for the exploration and production of oil and gas for a number of years. Many of these properties have been operated by third parties whose treatment or release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, may be subject to CERCLA, and we could potentially be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination. States also have environmental cleanup laws analogous to CERCLA, including Texas.

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA. While there is currently an exclusion from RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or gas, it is possible that some of these wastes could be classified as hazardous waste in the future and therefore be subject to more stringent regulation under RCRA. For example, in December 2016, the EPA and certain environmental organizations entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production-related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have an adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Oil Pollution Act. The Oil Pollution Act of 1990, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term "waters of the United States" has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs, and certain other damages arising from a spill. As such, a violation of the OPA has the potential to adversely affect our business, financial condition, results of operations and cash flows.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into regulated waters, such as waters of the United States. The discharge of pollutants, including dredge or fill materials in regulated wetlands, into regulated waters or wetlands without a permit issued by the EPA, the U.S. Army Corps of Engineers, or the Corps, or the state is prohibited. The Clean Water Act has been interpreted by these agencies to apply broadly. The EPA and the Corps released a rule to revise the definition of "waters of the United States," or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. In January 2017, the United States Supreme Court accepted review of the rule to determine whether jurisdiction to hear challenges to the rule rests with the federal district or appellate courts. In January 2018, the Supreme Court ruled that district courts have jurisdiction over challenges to the rule. EPA has instituted rulemakings to both delay the effective date of this rule and repeal the rule. Federal district court decisions have preserved the stay of the 2015 Clean Water Rule in Texas, which remains subject to pre-2015 regulated waters regulations, whereas the stay has been enjoined in a minority of states. Litigation surrounding this rule is ongoing. More recently, on December 11, 2018, the EPA and the Corps released a proposal to revise the 2015 Clean Water Rule so as to narrow the regulatory definition of waters of the United States, with a 60-day comment period to follow.

The Clean Water Act also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil. In 2016, the EPA finalized new wastewater pretreatment standards that would prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Safe Drinking Water Act. The Safe Drinking Water Act, or the SDWA, and the Underground Injection Control Program promulgated under the SDWA, establish the requirements for salt water disposal well activities and prohibit the migration of fluid-containing contaminants into underground sources of drinking water. The Underground Injection Well Program requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. In addition, in some instances, the operation of underground injection wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells, and regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission, or TRC, adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water or other oil and gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be, or determined to be, contributing to seismic activity, then TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that disposal well. TRC has used this authority to deny permits for waste disposal wells. The potential adoption of federal, state and local legislation and regulations intended to address induced seismic activity in the areas in which we operate could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays like the Eagle Ford formation, and is generally exempted from federal regulation as underground injection (unless diesel is a component of the fracturing fluid) under the SDWA. In addition, separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to induced seismicity. The EPA also released the results of its comprehensive research study to investigate the potential adverse impacts of hydraulic fracturing on drinking water and ground water in December 2016, finding that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. These developments could establish an additional level of regulation, including a removal of the exemption for hydraulic fracturing from the SDWA, and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing. Such costs and burdens could delay the development of unconventional gas resources from shale formations, which are not commercially feasible without the use of hydraulic fracturing.

Chemical Disclosures Related to Hydraulic Fracturing. Certain states in which we operate have adopted regulations requiring the disclosure of chemicals used in the hydraulic fracturing process. For instance, Texas has implemented chemical disclosure requirements for hydraulic fracturing operations. We currently disclose all hydraulic fracturing additives we use on www.FracFocus.org, a website created by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

Prohibitions and Other Regulatory Limitations on Hydraulic Fracturing. There have been a variety of regulatory initiatives at the state level to restrict oil and gas drilling operations in certain locations.

In addition to chemical disclosure rules, some states have implemented permitting, well construction or water withdrawal regulations that may increase the costs of hydraulic fracturing operations. For example, Texas has water withdrawal restrictions allowing suspension of withdrawal rights in times of shortages while other states require reporting on the amount of water used and its source.

Increased regulation of and attention given by environmental interest groups, as well as state and federal regulatory authorities, to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or existing wells. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing that are more stringent could cause a decrease in the completion of new oil and gas wells, as well as increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We use hydraulic fracturing extensively and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and gas that we can economically recover.

Clean Air Act. Our operations are subject to the Clean Air Act, or the CAA, and comparable state and local requirements. In 1990, the U.S. Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed, and continue to develop, regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Further, stricter requirements could negatively impact our production and operations. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

On April 17, 2012, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells, compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. Further, in May 2016, the EPA issued final NSPS governing methane emissions from the oil and gas industry as well as source determination standards for determining when oil and gas sources should be aggregated for CAA permitting and compliance purposes. The NSPS for methane extends the 2012 NSPS to completions of hydraulically fractured oil wells, equipment leaks, pneumatic pumps and natural gas compressors. In June 2017, the EPA proposed a two year stay of the fugitive emissions monitoring requirements, pneumatic pump standards and closed vent system certification requirements in the 2016 NSPS rule for the oil and gas industry while it reconsiders these aspects of the rule. The proposal is still under consideration. More recently, in September 2018, the EPA proposed targeted improvements to the rule, including amendments to the rule's fugitive emissions monitoring requirements, and expects to "significantly reduce" the regulatory burden of the rule in doing so. The U.S. Bureau of Land Management, or BLM, finalized similar rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM adopted final rules in January 2017; operators generally had one year from the January 2017 effective date of the rule to come into compliance with the rule's requirements. However, in December 2017, the BLM temporarily suspended or delayed certain of these requirements set forth in its Venting and Flaring Rule until January 2019, and in September 2018, the BLM proposed a revised rule which would scale back the waste-prevention requirements of the 2016 rule. Environmental groups sued in federal district court a day later to challenge the legality of aspects of the revised rule, and the outcome of this litigation is currently uncertain. These rules have required changes to our operations, including the installation of new equipment to control emissions. The EPA had announced in 2016 an intent to impose methane emission standards for existing sources, but the agency was sued by multiple states for failing to implement these standards following the agency's withdrawal of information collection requests for oil and gas facilities. These rules would result in an increase to our operating costs and change to our operations. As a result of this continued regulatory focus, future federal and state regulations of the oil and gas industry remain a possibility and could result in increased compliance costs on our operations.

In November 2015, the EPA revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. The EPA finished promulgating final area designations under the new standard in 2018, which, to the extent areas in which we operate have been classified as non-attainment, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Generally, it will take the states several years to develop compliance plans for their non-attainment areas. While we are not able to determine the extent to which this new standard will impact our business at this time, it has the potential to have a material impact on our operations and cost structure.

In June 2016, the EPA finalized a rule "aggregating" individual wells and other facilities and their collective emissions for purposes of determining whether major source permitting requirements apply under the CAA. These changes may introduce uncertainty into the permitting process and could require more lengthy and costly permitting processes and more expensive emission controls.

Collectively, these rules and proposed rules, as well as any future laws and their implementing regulations, may require a number of modifications to our operations. We may, for example, be required to install new equipment to control emissions from our well sites or compressors at initial startup or by the applicable compliance deadline. We may also be required to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Greenhouse Gas Emissions. In response to findings that emissions of carbon dioxide, methane and other "greenhouse gases," or GHGs, present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources.

Both in the United States and worldwide, there is increasing attention being paid to the issue of climate change and the contributing effect of GHG emissions. Most recently in April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

In August 2015, the EPA issued new regulations limiting carbon dioxide emissions from existing power generation facilities. Under this rule, nationwide carbon dioxide emissions would be reduced by approximately 30 percent from 2005 levels by 2030 with a flexible interim goal. Several industry groups and states challenged the rule. On February 9, 2016, the U.S. Supreme Court stayed the implementation of this rule pending judicial review. On March 28, 2017, President Trump signed an Executive Order directing the EPA to review the regulations, and on April 4, 2017, the EPA announced that it was reviewing the 2015 carbon dioxide regulations. On April 28, 2017, the U.S. Court of Appeals for the District of Columbia stayed the litigation pending the current administration's review. That stay was extended for another 60 days on August 8, 2017. On October 10, 2017, the EPA initiated the formal rulemaking process to repeal the regulations, which has not been finalized. In August 2018, the EPA proposed the Affordable Clean Energy rule (ACE) as a replacement to the 2015 regulations. ACE primarily addresses onsite efficiency improvements for power plants and does not require generation-shifting to low- or zero-emitting energy sources. The EPA's proposals will be subject to public comment or legal challenge, and as such we cannot predict at this time what impact the rulemakings will have on the demand for oil and gas production and our operations.

The EPA has issued the "Final Mandatory Reporting of Greenhouse Gases" Rule and a series of revisions to it, which requires operators of oil and gas production, natural gas processing, transmission, distribution and storage facilities and other stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. These rules do not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

In certain circumstances, large sources of GHG emissions are subject to preconstruction permitting under the EPA's Prevention of Significant Deterioration program. This program historically has had minimal applicability to the oil and gas production industry. However, there can be no assurance that our operations will avoid applicability of these or similar permitting requirements, which impose costs relating to emissions control systems and the efforts needed to obtain the permit.

Additional GHG regulations potentially affecting our industry include those described above under the subheading "Clean Air Act" which relate to methane.

Future federal GHG regulations of the oil and gas industry remain a possibility. Also, many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities. Many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. While it is not possible to predict how any regulations to restrict GHG emissions may come into force, these and other legislative and regulatory proposals for restricting GHG emissions or otherwise addressing climate change could require us to incur additional operating costs or curtail oil and gas operations in certain areas and could also adversely affect demand for the oil and gas we sell.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations, and the provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered species or their habitats. While some of our facilities are in areas that may be designated as a habitat for endangered species, we believe that we are in substantial compliance with the Endangered Species Act. The presence of any protected species or the final designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs from species protection measures or could result in limitations, delays, or prohibitions on our exploration and production activities that could have an adverse effect on our ability to develop and produce our reserves.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment of the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. This process has the potential to delay or even halt development of some of our oil and gas projects.

Employees and Labor Relations

We had a total of 95 employees as of December 31, 2018. We hire independent contractors on an as needed basis. We consider our current employee relations to be favorable. We and our employees are not subject to any collective bargaining agreements.

Available Information

Our internet address is http://www.pennvirginia.com. We make available free of charge on or through our website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter and Nominating and Governance Committee Charter, and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Investors can obtain current and important information about the company from our website on a regular basis. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we furnish or file with the SEC. We intend for our website to serve as a means of public dissemination of information for purposes of Regulation FD.

Item 1A Risk Factors

Our business and operations are subject to a number of risks and uncertainties as described below; however, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition, results of operations and cash flows in the future. If any of the following risks actually occur, our business, financial condition, results of operations and cash flows could suffer and the trading price of our common stock could decline.

Risk Factors Associated with the Merger

There can be no assurance that we will obtain shareholder approval for the Merger or that the Merger will be consummated.

There can be no assurance that the Merger will be consummated and our shareholders will receive the merger consideration. The completion of the Merger is subject to various closing conditions and termination rights (including if the Merger is not consummated by April 30, 2019). In addition to other conditions that are beyond our control, the Merger is subject to approval by the holders of more than two-thirds of the outstanding Company common shares, the approval by the holders of a majority of the outstanding Denbury common shares of an amendment to the certificate of incorporation to increase the number of authorized Denbury common shares, and the approval of the issuance of Denbury common shares in the Merger by the holders of a majority of the Denbury common shares represented in person or by proxy at a meeting of Denbury shareholders held to vote on such matters. We cannot guarantee that the closing conditions set forth in the Merger Agreement will be satisfied or, even if satisfied, that no event of termination will take place. The completion of the Merger is not assured and is subject to risks, including the risk that the approval of our shareholders or Denbury's stockholders is not obtained. Activist shareholders may increase the risk that the requisite votes are not obtained. In that regard, one shareholder of the Company (Mangrove Partners) has engaged in a public campaign to prevent shareholder approval of the Merger, which campaign includes a preliminary proxy statement filed on January 17, 2019, that solicits votes in opposition to the Merger. Other Company shareholders or Denbury stockholders could oppose the proposals for approval of the Merger. Any such campaign could result in substantial costs and divert each company's respective management's and directors' attention and resources from each company's respective business. Moreover, the Merger Agreement contains conditions, some of which are beyond our control, that, if not satisfied or waived, may prevent, delay or otherwise result in the Merger not occurring.

Because the exchange ratio in the Merger Agreement is fixed and because the market price of Denbury common stock will fluctuate prior to the completion of the Merger, our shareholders cannot be sure of the market value of the Denbury common stock they will receive as Merger consideration relative to the value of the cash and shares of common stock they exchange at the closing.

Under the terms of the Merger Agreement, our shareholders will receive the Merger Consideration, consisting of a combination of 12.4 shares of Denbury common stock and $25.86 of cash for each share of Company common stock, subject to election of the Company shareholders to receive either all cash, all stock or a mix of stock and cash, in each case subject to proration. Based on the closing price of Denbury common stock on October 26, 2018, the Merger Consideration represented consideration to each Company shareholder of $79.80 per share. The exchange ratio for the Merger Consideration is fixed, and there will be no adjustment to the Merger Consideration for changes in the market price of Denbury's common stock or our common stock prior to the completion of the Merger.

If the Merger is completed, there will be a time lapse between the date of signing of the Merger Agreement and the date on which our shareholders who are entitled to receive the Merger Consideration actually receive the Merger Consideration. The market value of shares of Denbury's common stock and our common stock has fluctuated and may continue to fluctuate during this period as a result of a variety of factors, including general market and economic conditions, changes in each company's business, operations and prospects, commodity prices, regulatory considerations, and the market's assessment of Denbury's business and the Merger. Such factors are difficult to predict and in many cases may be beyond the control of Denbury and us. The actual value of any Merger Consideration received by our shareholders at the completion of the Merger will depend on the market value of the shares of Denbury common stock at that time. This market value may differ, possibly materially, from the market value of shares of Denbury common stock at the time the Merger Agreement was entered into or at any other time. The market value of shares of Denbury Common Stock has declined from $4.35 per share on the trade date immediately prior to the public announcement of the Merger to $2.14 per share on February 22, 2019, and the market value of the Company common stock per share has decreased from $67.39 to $56.24 in the same period. If the trading price of Denbury common stock at the closing of the Merger is less than the trading price of Denbury common stock on the date that the Merger Agreement was signed, particularly if the trading price of the Company common stock increases, then the market value of the Merger Consideration will be less than contemplated at the time the Merger Agreement was signed. This could make it more difficult to obtain shareholder approval of and complete the Merger.

Even if Denbury and the Company complete the Merger, Denbury may fail to realize all of the anticipated benefits of the Merger.

Even if we complete the Merger, the combined company may not realize the benefits and guidance provided by either Denbury or us, including due to factors beyond the control of the combined company's management. The success of the Merger will depend, in part, on Denbury's ability to realize the anticipated financial benefits from combining Denbury's and the Company's businesses, including synergies. The anticipated financial benefits of the Merger may not be realized fully or at all, may take longer to realize than expected or could have other adverse effects that neither we nor Denbury currently foresee. Some of the assumptions that we have made, such as the achievement of synergies, may not be realized. The integration process may, for each of Denbury and the Company, result in the loss of key employees, the disruption of ongoing businesses or inconsistencies in standards, controls, procedures and policies. There could be potential unknown liabilities and unforeseen expenses associated with the Merger that were not discovered in the course of performing due diligence.

The Merger involves numerous operational, strategic, financial, accounting, legal, tax and other risks, potential liabilities associated with the acquired businesses, and uncertainties related to design, operation and integration of the Company's internal control over financial reporting. Difficulties in integrating the Company into Denbury may result in the combined company performing differently than expected, in operational challenges or in the failure to realize anticipated expense-related efficiencies. Denbury's and the Company's existing businesses could also be negatively impacted by the Merger. Potential difficulties that may be encountered in the integration process include, among other factors:

- the inability to successfully integrate the businesses of the Company into Denbury in a manner that permits the combined company to achieve the full financial benefits anticipated from the Merger;
- complexities associated with managing the larger, more complex, integrated business;
- not realizing anticipated synergies;
- integrating personnel from the two companies and the loss of key employees;
- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with the Merger;
- integrating relationships with customers, vendors and business partners;
- performance shortfalls at one or both of the companies as a result of the diversion of management's attention caused by completing the Merger and integrating the Company's operations into Denbury; and
- the disruption of, or the loss of momentum in, each company's ongoing business or inconsistencies in standards, controls, procedures and policies.

We will incur significant transaction and Merger-related costs in connection with the Merger, which may be in excess of those anticipated by us.

We have incurred and expect to continue to incur a number of non-recurring costs associated with negotiating and completing the Merger, obtaining shareholder approval (including responding to any activist shareholders) and combining the operations of the two companies. These fees and costs have been, and will continue to be, substantial. The substantial majority of non-recurring expenses will consist of transaction costs related to the Merger and include, among others, employee retention costs, fees paid to financial, legal and accounting advisors, severance and benefit costs and filing fees.

We will also incur transaction fees and costs related to formulating and implementing integration plans, including facilities and systems consolidation costs and employment-related costs. We will continue to assess the magnitude of these costs, and additional unanticipated costs may be incurred in the Merger and the integration of the two companies' businesses. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow Denbury and the Company to offset integration-related costs over time, this net benefit may not be achieved in the near term, or at all. The costs described above, as well as other unanticipated costs and expenses, could have a material adverse effect on the financial condition and operating results of Denbury following the completion of the Merger. Many of these costs will be borne by us even if the Merger is not completed.

Completion of the Merger may trigger change in control or other provisions in certain agreements to which we are a party.

The completion of the Merger may trigger change in control or other provisions in certain agreements to which we are a party. If we are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages. Even if we are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements on terms less favorable to us.

The Merger Agreement limits our ability to pursue alternatives to the Merger.

The Merger Agreement contains provisions that may discourage a third party from submitting a competing proposal that might result in greater value to our shareholders than the Merger, or may result in a potential competing acquirer of the Company proposing to pay a lower per share price to acquire the Company than it might otherwise have proposed to pay. These provisions include a general prohibition on us from soliciting or, subject to certain exceptions relating to the exercise of fiduciary duties by our board, entering into discussions with any third party regarding any competing proposal or offer for a competing transaction. Even upon termination of the Merger Agreement under certain circumstances relating to the exercise of fiduciary duties by our board, we may be required to pay Denbury fees and expenses, which may further deter counterparties to any potential alternative transaction.

Failure to complete the Merger could negatively impact the price of shares of our common stock, as well as our future businesses and financial results.

The Merger Agreement contains a number of conditions that must be satisfied or waived prior to the completion of the Merger. There can be no assurance that all of the conditions to the completion of the Merger will be so satisfied or waived. If these conditions are not satisfied or waived, we will be unable to complete the Merger. If the Merger is not completed for any reason, including the failure to receive the required approval of our shareholders or Denbury's stockholders, our businesses and financial results may be adversely affected, including as follows:

- we may experience negative reactions from the financial markets, including negative impacts on the market price of our common stock;
- the manner in which customers, vendors, business partners and other third parties perceive the Company may be negatively impacted, which in turn could affect our marketing operations or our ability to compete for new business or obtain renewals in the marketplace more broadly;
- we may experience negative reactions from employees; and
- we will have expended time and resources that could otherwise have been spent on our existing businesses and the pursuit of other opportunities that could have been beneficial to the Company, and our ongoing business and financial results may be adversely affected.

In addition to the above risks, if the Merger Agreement is terminated and our board seeks an alternative transaction, our shareholders cannot be certain that we will be able to find a party willing to engage in a transaction on more attractive terms than the Merger. If the Merger Agreement is terminated under specified circumstances, we may be required to pay Denbury a $45 million termination fee.

We will be subject to business uncertainties while the Merger is pending, which could adversely affect our businesses.

Uncertainty about the effect of the Merger on employees and customers may have an adverse effect on the Company. These uncertainties may impair our ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter and could cause customers and others that deal with us to seek to change their existing business relationships with us. Employee retention at the Company may be particularly challenging during the pendency of the Merger, as employees may experience uncertainty about their roles. In addition, the Merger Agreement restricts us from entering into certain corporate transactions, entering into material contracts, changing our capital budget, incurring certain indebtedness and taking other specified actions without the consent of Denbury, and generally requires us to continue our operations in the ordinary course of business, until completion of the Merger. These restrictions may prevent us from pursuing attractive business opportunities or adjusting our capital plan prior to the completion of the Merger.

We may be a target of securities class action and derivative lawsuits that could result in substantial costs and may delay or prevent the Merger from being completed.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into merger agreements. For example, on February 25, 2019, a shareholder of the Company filed a lawsuit against us, the members of our board, Denbury and the other entities involved in the Merger in the U.S. District Court for the Southern District of Texas, Houston Division. The plaintiff alleges that the registration statement filed by the defendants omitted material information with respect to the Merger, which renders such registration statement false and misleading, and is seeking, among other things, injunctive relief to prohibit the completion of the Merger and monetary damages in the form of plaintiff's costs to bring the lawsuit. Even if the lawsuits are without merit, such as the recently filed lawsuit described in the preceding sentence, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on our liquidity and financial condition. Additionally, if a plaintiff is successful in obtaining an injunction prohibiting completion of the Merger, then that injunction may delay or prevent the Merger from being completed, which may adversely affect our and Denbury's business, financial position and results of operation.

Uncertainties associated with the Merger may cause a loss of management personnel and other key employees, which could adversely affect the future business and operations of the combined company.

We and Denbury are dependent on the experience and industry knowledge of our officers and other key employees to execute our business plans. Each company's success until the Merger and the combined company's success after the Merger will depend in part upon the ability of us and Denbury to retain key management personnel and other key employees. Current and prospective employees of Denbury and the Company may experience uncertainty about their roles within the combined company following the Merger, which may have an adverse effect on the ability of each of us and Denbury to attract or retain key management and other key personnel. Accordingly, no assurance can be given that the combined company will be able to attract or retain key management personnel and other key employees of Denbury and the Company to the same extent that we and Denbury have previously been able to attract or retain their own employees.

Risk Factors Associated with our General Business

Prices for crude oil, NGLs and natural gas are dependent on many factors that are beyond our control.

Prices for crude oil, NGLs and natural gas are dependent on many factors that are beyond our control, including:

- domestic and foreign supplies of crude oil, NGLs and natural gas;
- domestic and foreign consumer demand for crude oil, NGLs and natural gas;
- political and economic conditions in oil or gas producing regions;
- the extent to which the members of the Organization of Petroleum Exporting Countries and other oil exporting nations agree upon and maintain production constraints and oil price controls;
- overall domestic and foreign economic conditions;
- prices and availability of, and demand for, alternative fuels;
- the effect of energy conservation efforts;
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil, natural gas and NGLs so as to minimize emissions of carbon dioxide and methane GHGs;
- volatility and trading patterns in the commodity-futures markets;
- technological advances affecting energy consumption and energy supply;
- political and economic events that directly or indirectly impact the relative strength or weakness of the United States dollar, on which crude oil prices are benchmarked globally, against foreign currencies;
- risks related to the concentration of our operations in the Eagle Ford Shale field in South Texas;
- speculation by investors in oil and gas;
- the availability, cost, proximity and capacity of gathering, processing, refining and transportation facilities;
- the cost and availability of products and personnel needed for us to produce oil and gas;
- weather conditions; and
- domestic and foreign governmental relations, regulation and taxation, including limits on the United States' ability to export crude oil.

Oil and natural gas prices continued to be volatile in 2018. For example, the NYMEX oil prices in 2018 ranged from a high of $60.42 to a low of $42.53 per Bbl and the NYMEX natural gas prices in 2018 ranged from a high of $3.72 to a low of $2.56 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached highs of approximately $57 per Bbl and $3.60 per MMBtu, respectively, during the period from January 1, 2019, to February 22, 2019. It is impossible to predict future commodity price movements with certainty; however, many of our projections and estimates are based on assumptions as to the future prices of crude oil, NGLs and natural gas. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future will likely differ from our estimates. Any substantial or extended decline in the actual prices of crude oil, NGLs or natural gas would have a material adverse effect on our business, financial position, results of operations, cash flows and borrowing capacity, the quantities of oil and gas reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

Exploration and development drilling are high-risk activities with many uncertainties and may not result in commercially productive reserves.

Our future financial condition and results of operations depend on the success of our exploration and production activities. Oil and gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and gas production. The costs of drilling, completing and operating wells are often substantial and uncertain, and drilling and completion operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control, including:

- unexpected drilling conditions;
- the use of multi-well pad drilling that requires the drilling of all of the wells on a pad until any one of the pad's wells can be brought into production;
- risks associated with drilling horizontal wells and extended lateral lengths, such as deviating from the desired drilling zone or not running casing or tools consistently through the wellbore, particularly as lateral lengths get longer;
- fracture stimulation accidents or failures;
- reductions in oil, natural gas and NGL prices;
- elevated pressure or irregularities in geologic formations;
- loss of title or other title related issues;
- equipment failures or accidents;
- costs, shortages or delays in the availability of drilling rigs, frac fleets, crews, equipment and materials;
- shortages in experienced labor;
- crude oil, NGLs or natural gas gathering, transportation, processing, storage and export facility availability restrictions or limitations;
- surface access restrictions;
- delays imposed by or resulting from compliance with regulatory requirements, including any hydraulic fracturing regulations and other applicable regulations, and the failure to secure or delays in securing necessary regulatory, contractual and third-party approvals and permits;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- environmental hazards, such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- limited availability of financing at acceptable terms;
- limitations in the market for crude oil, natural gas and NGLs;
- fires, explosions, blow-outs and surface cratering;
- adverse weather conditions; and
- actions by third-party operators of our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The type curves we use in our development plans from time to time are only estimates of performance of the acreage we might develop and actual production can differ materially. Furthermore, the cost of drilling, completing, equipping and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. In addition, limitations on the use of hydraulic fracturing could have an adverse effect on our ability to develop and produce oil and gas from new wells, which would reduce our rate of return on these wells and our cash flows. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, and we cannot be sure that our overall drilling success rate or our drilling success rate within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our business, financial condition, results of operations and cash flows. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or gas from all of them.

Multi-well pad drilling and project development may result in volatility in our operating results.

We utilize multi-well pad drilling and project development where practical. Project development may involve more than one multi-well pad being drilled and completed at one time in a relatively confined area. Wells drilled on a pad or in a project may not be brought into production until all wells on the pad or project are drilled and completed. Problems affecting one pad or a single well could adversely affect production from all of the wells on the pad or in the entire project. As a result, multi-well pad drilling and project development can cause delays in the scheduled commencement of production, or interruptions in ongoing production. These delays or interruptions may cause declines or volatility in our operating results due to timing as well as declines in oil and natural gas prices. Further, any delay, reduction or curtailment of our development and producing operations, due to operational delays caused by multi-well pad drilling or project development, or otherwise, could result in the loss of acreage through lease expirations.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs and crews, frac crews, and related equipment and material; and
- the availability of leases and permits on reasonable terms for the prospects.

Although we have identified numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. There can be no assurance that these projects can be successfully developed or that any identified drill sites will, if drilled, encounter reservoirs of commercially productive oil or gas or that we will be able to complete such wells on a timely basis, or at all. We may seek to sell or reduce all or a portion of our interest in a project area or with respect to prospects wells within such project area.

Our business depends on gathering, processing, refining and transportation facilities owned by others.

We deliver substantially all of our oil and gas production through pipelines and trucks that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines and trucks, as well as gathering systems, gas processing facilities and downstream refineries. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells, the reduction in wellhead pricing or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather, process, refine and market our oil and gas.

The unavailability, high cost or shortage of drilling rigs, frac crews, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

Where we are the operator of a property, we rely on third-party service providers to perform necessary drilling and completion operations. The ability and availability of third-party service providers to perform such drilling and completion operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, NGLs and natural gas, prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations on a timely basis could delay drilling or completion operations, reduce production from the property or cause other damage to operations, each of which could adversely affect our business, financial condition, results of operations and cash flows.

Moreover, the oil and gas industry is cyclical, which can result in shortages of drilling rigs, frac crews, equipment, raw materials (particularly sand and other proppants), supplies and personnel, including geologists, geophysicists, engineers and other professionals. When shortages occur, the costs and delivery times of drilling rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig and frac crews also rise with increases in demand. The prevailing prices of crude oil, NGLs and natural gas also affect the cost of and the demand for drilling rigs, frac crews, materials (including sand) and other equipment and related services. The availability of drilling rigs, frac crews, materials (including sand) and equipment can vary significantly from region to region at any particular time. Although land drilling rigs and frac crews can be moved from one region to another in response to changes in levels of demand, an undersupply in any region may result in drilling and/or completion delays and higher well costs in that region.

We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. In accordance with customary industry practice, we rely on independent third-party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs and frac crews at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. Shortages of drilling rigs, frac crews, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operating activities. We must make substantial capital expenditures to find, acquire, develop and produce new oil and gas reserves. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves with our cash flows from operating activities. Furthermore, external sources of capital may be limited.

The ability to attract and retain key personnel is critical to the success of our business and may be challenging.

The success of our business depends on key personnel. The ability to attract and retain these key personnel may be difficult in light of the volatility of our business. We may need to enter into retention or other arrangements that could be costly to maintain. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them adequately or in a timely manner and we could experience significant declines in productivity.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on the acreage.

Leases on oil and gas properties typically have a term after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory through drilling wells to hold the leasehold acreage that we believe is material to our operations, our drilling plans for these areas are subject to change and subject to the availability of capital.

We are exposed to the credit risk of our customers, and nonpayment or nonperformance by these parties would reduce our cash flows.

We are subject to risk from loss resulting from our customers' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of our revenues. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly affect our overall credit risk. Recently, many of our customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payments or perform on their obligations to us. In 2018, approximately 69 percent of our total consolidated product revenues resulted from three of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

We participate in oil and gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100 percent of the working interest in the oil and gas leases on which we conduct operations, and other parties own the remaining portion of the working interest under joint venture arrangements. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one party. We could be held liable for joint venture obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the volatility in commodity prices increases the likelihood that some of these working interest owners may not be able to fulfill their joint venture obligations. Some of our project partners have experienced liquidity and cash flow problems. These problems have led and may lead our partners to continue to attempt to delay the pace of project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial condition, results of operations and cash flows.

Estimates of oil and gas reserves and future net cash flows are not precise, and undeveloped reserves may not ultimately be converted into proved producing reserves.

This Annual Report on Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various factors and assumptions, including assumptions relating to crude oil, NGL and natural gas prices, drilling and operating expenses, capital expenditures, development costs and workover and remedial costs, the quantity, quality and interpretation of relevant data, taxes and availability of funds. The process of estimating oil and gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and inherently uncertain, therefore, changes often occur as these variables evolve and commodity prices fluctuate. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Any material inaccuracies in these reserve estimates, cash flow estimates or underlying assumptions could materially affect the estimated quantities and present value of our reserves.

Actual future production, crude oil, NGL and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil, NGL and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2018, approximately 62 percent of our estimated proved reserves were proved undeveloped, compared to 56 percent at December 31, 2017. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve data assumes that we can and will make these significant expenditures to develop our reserves and conduct these drilling operations successfully. These assumptions, however, may not prove correct, and our estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

The reserve estimation standards under SEC rules provide that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These standards may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not develop those reserves within the required five-year time frame or cannot demonstrate that we could do so. Accordingly, our reserve report at December 31, 2018, includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $1,175 million. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. During the year ended December 31, 2018, we wrote-off 21.1 MMBOE of proved undeveloped reserves because they are no longer expected to be developed within five years of their initial recording. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

You should not assume that the present value of estimated future net cash flows (standardized measure) referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. Actual future net cash flows may also be affected by the amount and timing of actual production, availability of financing for capital expenditures necessary to develop our undeveloped reserves, supply and demand for oil and gas, increases or decreases in consumption of oil and gas and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for us. With all other factors held constant, if commodity prices used in the reserve report were to decrease by 10%, our standardized measure and PV-10 would have decreased to approximately $1,325.7 million and $1,444.4 million, respectively. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may record impairments on our oil and gas properties.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower crude oil, NGL and natural gas prices may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all reserves within such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depreciation, depletion and amortization, or DD&A, on the affected properties, which would decrease earnings or result in losses through higher DD&A expense. The revisions may also be significant enough to result in a write-down that would further decrease reported earnings.

The full cost method of accounting for oil and gas properties under GAAP requires that at the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes, or a Ceiling Test. The estimated discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development. In addition to revisions to reserves and the impact of lower commodity prices, Ceiling Test write-downs may occur due to increases in estimated operating and development costs and other factors. During the past several years, we have been required to write down the value of certain of our oil and gas properties and related assets. We could experience additional write-downs in the future.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our business strategy.

The oil and gas industry is capital intensive. We incur and expect to continue to incur substantial capital expenditures for the acquisition, exploration and development of oil and gas reserves. We incurred approximately $533 million in acquisition, exploration and development costs during the year ended December 31, 2018. We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and, if necessary, through borrowings under our credit facility. However, our cash flow from operations and access to capital are subject to a number of variables, including: (i) the volume of oil and gas we are able to produce from existing wells, (ii) our ability to transport our oil and gas to market, (iii) the prices at which our commodities are sold, (iv) the costs of producing oil and gas, (v) global credit and securities markets, (vi) the ability and willingness of lenders and investors to provide capital and the cost of the capital, (vii) our ability to acquire, locate and produce new reserves and (viii) our proved reserves.

We may not generate expected cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our business strategy, we may be required to curtail operations, which could adversely affect our financial condition, results of operations and cash flows.

Our property acquisitions carry significant risks.

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. In the event we do complete an acquisition, its success will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future crude oil, NGL and natural gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment, possible future environmental or other liabilities and the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and the assumption of potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems, that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

Our initial technical reviews of properties we acquire are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with acquired properties, or discover unknown liabilities after the acquisition, and such risks and liabilities could have a material adverse effect on its results of operations and financial condition.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the oil and gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations, financial condition and cash flows. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forgo the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. Even then, the cost of performing detailed title work can be expensive. We may choose to forgo detailed title examination by title lawyers on a portion of the mineral leases that we place in a drilling unit or conduct less title work than we have traditionally performed. As is customary in our industry, we generally rely upon the judgment of oil and gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and before drilling a well on a leased tract. We, in some cases, perform curative work to correct deficiencies in the marketability or adequacy of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and gas leases can be generally lost and the target area can become undrillable. The failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

As a small company, we face unique difficulties competing in the larger market.

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel, and we may face difficulties in competing with larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and gas plays, to acquire new acreage, and to develop attractive oil and gas projects, are significant. We face intense competition in all areas of our business from companies with greater and more productive assets, greater access to capital, substantially larger staffs and greater financial and operating resources than we have. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our limited size has placed us at a disadvantage with respect to funding our capital and operating costs, and means that we are more vulnerable to commodity price volatility and overall industry cycles, are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development or production play can have a disproportionately negative impact on us. We also compete for people, including experienced geologists, geophysicists, engineers and other professionals. Our limited size has placed us at a disadvantage with respect to attracting and retaining management and other professionals with the technical abilities necessary to successfully operate our business.

Our lack of diversification increases the risk of an investment in us and we are vulnerable to risks associated with operating primarily in one major contiguous area.

All of our operations are in the Eagle Ford Shale in South Texas, making us vulnerable to risks associated with operating in one geographic area. Due to the concentrated nature of our business activities, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that are more diversified. In particular, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, water shortages or other drought related conditions, plant closures for scheduled maintenance or interruption of transportation of crude oil or natural gas produced from wells in the Eagle Ford. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations and cash flows.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had $521 million of outstanding debt at December 31, 2018, including $321 million under the Credit Agreement as amended, or the Credit Facility, and $200 million, excluding unamortized discount and issuance costs, under the $200 million Second Lien Credit Agreement, or the Second Lien Facility.

Our indebtedness and any increase in our level of indebtedness could have adverse effects on our financial condition, results of operations and cash flows, including (i) imposing additional cash requirements on us in order to support interest payments, which reduces the amount we have available to fund our operations and other business activities, (ii) increasing the risk that we may default on our debt obligations, (iii) increasing our vulnerability to adverse changes in general economic and industry conditions, economic downturns and adverse developments in our business, (iv) limiting our ability to engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes and (v) limiting our flexibility in planning for or reacting to changes in our business and industry in which we operate. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are out of our control.

The borrowing base under our credit facility may be reduced in the future if commodity prices decline.

The borrowing base under the Credit Facility, was $450 million as of December 31, 2018. Our borrowing base is redetermined at least twice each year and is scheduled to next be redetermined in April 2019. If crude oil, NGL or natural gas prices decline, the borrowing base under the Credit Facility may be reduced. As a result, we may be unable to obtain funding under the Credit Facility. If funding is not available when or in the amounts needed, or is available only on unfavorable terms, it might adversely affect our development plan and our ability to make new acquisitions, each of which could have a material adverse effect on our production, financial condition, results of operations and cash flows.

The Credit Facility and the Second Lien Facility have restrictive covenants that could limit our financial flexibility.

The Credit Facility and Second Lien Facility contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including leverage, interest coverage and current ratios.

The Credit Facility and the Second Lien Facility include other restrictions that, among other things, limit our ability to incur indebtedness; grant liens; engage in mergers, consolidations and liquidations; make asset dispositions, restricted payments and investments; enter into transactions with affiliates; and amend, modify or prepay certain indebtedness.

Our business plan and our compliance with these covenants are based on a number of assumptions, the most important of which is relatively stable oil and gas prices at economically sustainable levels. If the price that we receive for our oil and gas production deteriorates significantly from current levels it could lead to lower revenues, cash flows and earnings, which in turn could lead to a default under certain financial covenants contained in our Credit Facility. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period as the amounts outstanding under our Credit Facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings. Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our debts. We may not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations, financial condition or cash flows. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations or other environmental, health or safety impacts, we may be charged with remedial costs and land owners may file claims for alternative water supplies, property damage or bodily injury. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our business, financial condition, results of operations and cash flows. See Part I, Item 1, “Business - *Government Regulation and Environmental Matters*.”

Our business involves many operating risks, including hydraulic fracturing, that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for and the production and transportation of oil and gas, including well stimulation and completion activities such as hydraulic fracturing. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures or structures;
- pipeline ruptures or spills;
- mechanical difficulties, such as stuck oilfield drilling and service tools;
- uncontrollable flows of oil, natural gas or well fluids;
- migration of fracturing fluids into surrounding groundwater;
- spills or releases of fracturing fluids including from trucks sometimes used to deliver these materials;
- spills or releases of brine or other produced water that may go off-site;
- subsurface conditions that prevent us from (i) stimulating the planned number of stages, (ii) accessing the entirety of the wellbore with our tools during completion or (iii) removing all fracturing-related materials from the wellbore to allow production to begin;
- environmental hazards such as natural gas leaks, oil or produced water spills and discharges of toxic gases; and
- natural disasters and other adverse weather conditions, terrorism, vandalism and physical, electronic and cyber security breaches.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean up responsibilities, regulatory investigations and penalties, loss of well location, acreage, expected production and related reserves and suspension of operations. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

If we experience any problems with well stimulation and completion activities, such as hydraulic fracturing, our ability to explore for and produce oil or natural gas may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of:

- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, which may include limitations on hydraulic fracturing or the discharge of GHGs;
- the need to shut down, abandon and relocate drilling operations;
- the need to sample, test and monitor drinking water in particular areas and to provide filtration or other drinking water supplies to users of water supplies that may have been impacted or threatened by potential contamination from fracturing fluids;
- the need to modify drill sites to ensure there are no spills or releases off-site and to investigate and/or remediate any spills or releases that might have occurred; or
- suspension of our operations.

In accordance with industry practice, we maintain insurance at a level that balances the cost of insurance with our assessment of the risk and our ability to achieve a reasonable rate of return on our investments. We cannot assure you that our insurance will be adequate to cover losses or liabilities or that we will purchase insurance against all possible losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Access to water to drill and conduct hydraulic fracturing may not be available if water sources become scarce, and we may face difficulty disposing of produced water gathered from drilling and production activities.

The availability of water is crucial to conduct hydraulic fracturing. A significant amount of water is necessary for drilling and completing each well with hydraulic fracturing. In the past, Texas has experienced severe droughts that have limited the water supplies that are necessary to conduct hydraulic fracturing. Although we have taken measures to secure our water supply, we can make no assurances that sufficient water resources will be available in the short or long term to carry out our current activities. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Climate change legislation, laws and regulations restricting emissions of greenhouse gases or legal or other action taken by public or private entities related to climate change could force us to incur increased capital and operating costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA began adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. For example, the EPA issued rules restricting methane emissions from hydraulically fractured and refractured gas wells, compressors, pneumatic controls, storage vessels, and natural gas processing plants. For more information on GHG regulation, see Part I, Item 1, "Business - *Government Regulation and Environmental Matters*."

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In the future, the United States may also choose to adhere to international agreements targeting GHG reductions. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, results of operations and cash flows. Reduced demand for the oil and gas that we produce could also have the effect of lowering the value of our reserves.

In addition, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such events were to occur, they could have an adverse effect on our financial condition, results of operations and cash flows. For a more complete discussion of environmental laws and regulations intended to address climate change and their impact on our business and operations, see Part I, Item 1, "Business - *Environmental Regulation - Climate Change*."

There have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Federal state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and gas production. We routinely use hydraulic fracturing to complete wells. The EPA released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of the EPA's study could spur action towards federal legislation and regulation of hydraulic fracturing or similar production operations. In past sessions, Congress has considered, but did not pass, legislation to amend the SDWA to remove the SDWA's exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and gas companies in the hydraulic fracturing process. The EPA has issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing; an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, a number of states and local regulatory authorities are considering or have implemented more stringent regulatory requirements applicable to hydraulic fracturing, including bans/moratoria on drilling that effectively prohibit further production of oil and gas through the use of hydraulic fracturing or similar operations. Texas has adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Moreover, the legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. In light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, Texas regulators have asserted regulatory authority to limit injection activities in certain wells in an effort to reduce seismic activity. A 2015 U.S. Geological Survey report identified areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil, natural gas and natural gas liquids activities utilizing injection wells for produced water disposal.

The adoption of new laws or regulations imposing reporting or operational obligations on, or otherwise limiting or prohibiting, the hydraulic fracturing process could make it more difficult to complete oil and gas wells in unconventional plays. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, hydraulic fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect our business and results of operations.

Restrictions on drilling activities intended to protect certain species of wildlife or their habitat may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Various federal and state statutes prohibit certain actions that harm endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act, CERCLA and the OPA. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling, construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, may seek criminal penalties.

Derivative transactions may limit our potential gains and involve other risks.

In order to achieve more predictable cash flows and manage our exposure to price risks in the sale of our crude oil, NGLs and natural gas, we periodically enter into commodity price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of three years or less. While intended to reduce the effects of volatile crude oil, NGL and natural gas prices, such transactions may limit our potential gains if crude oil, NGL or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how commodity prices fluctuate in the future, which could have the effect of reducing our net income.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparty to a derivatives instrument fails to perform under the contract; or
- a sudden, unexpected event materially impacts commodity prices.

In addition, we may enter into derivative instruments that involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

The adoption of derivatives legislation and implementing rules could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC, to promulgate rules and regulations implementing the Dodd-Frank Act. While some of these rules have been finalized, some have not been finalized or implemented, and it is not possible at this time to predict when this will be accomplished. In October

2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; however, this initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. The CFTC has subsequently issued proposals for new rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions for bona fide hedging transactions, though these rules have not been finalized and the impact of those provisions on us is uncertain at this time.

While the CFTC has designated certain interest rate swaps and credit default swaps subject to mandatory clearing, and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules subjecting any other classes of swaps, including physical commodity swaps, to mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If our swaps do not qualify for the commercial end-user exception from mandatory clearing, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or our ability to hedge may be impacted. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to be exempt from such requirements for the mandatory exchange of margin for uncleared swaps, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Further, if we do not qualify for an exemption and are required to post collateral for our swaps, it could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. When fully implemented, the Dodd-Frank Act and any new regulations could increase the operational and transactional cost of derivatives contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize and restructure our existing derivatives contracts and affect the number and/or creditworthiness of available counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

In addition, we may transact with counterparties based in the European Union, Canada or other jurisdictions which, like the U.S., are in the process of implementing regulations to regulate derivatives transactions, some of which are currently in effect and impose operational and transactional costs on our derivatives activities.

Our ability to use net operating loss carryforwards to offset future taxable income may be subject to certain limitations.

Our ability to utilize U.S. net operating loss, or NOL, carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended, or the Code. As disclosed in Note 11 to our Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data,” we have substantial NOL carryforwards. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of our stock by 5 percent shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50 percent in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. As of December 31, 2018, we do not believe that an ownership change has occurred; however, to the extent an ownership change has occurred or were to occur in the future, it is possible that the limitations imposed on our ability to use pre-ownership change losses could cause a significant net increase in our U.S. federal income tax liability and could cause U.S. federal income taxes to be paid earlier than they otherwise would be paid if such limitations were not in effect. In addition, U.S. NOLs generated on or after January 1, 2018, can be limited to 80 percent of taxable income. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated. Additional state taxes on oil and gas extraction may be imposed, as a result of future legislation.

In recent years, lawmakers and Treasury have proposed certain significant changes to U.S. tax laws applicable to oil and gas companies. These changes include, but are not limited to: (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes are ever made, as well as any similar changes in state law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations and cash flows.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our crude oil, NGLs and natural gas.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition, results of operations and cash flows could be adversely affected.

A cybersecurity incident could result in theft of confidential information, data corruption or operational disruption.

The oil and gas industry is increasingly dependent on digital technologies to conduct certain exploration, development and production activities. Software programs are used for, among other things, reserve estimates, seismic interpretation, modeling and compliance reporting. In addition, the use of mobile communication is widespread. Increasingly, we must protect our business against potential cyber incidents including attacks.

If our systems for protecting against cyber incidents prove insufficient, we could be adversely affected by unauthorized access to our digital systems which could result in theft of confidential information, data corruption or operational disruption. These cybersecurity threat actors are becoming more sophisticated and coordinated in their attempts to access a company's information technology systems and data, including the information technology systems of cloud providers and third parties with which a company conducts business. As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and enhance our protective systems or to investigate and remediate any vulnerabilities.

Information technology solution failures, network disruptions and breaches of data security could disrupt our operations by causing delays or cancellation of customer orders, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;
- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;
- A cyber attack on third-party gathering, pipeline, or other transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market;
- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- A cyber attack on our automated and surveillance systems could cause a loss in production and potential environmental hazards;
- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and
- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

Additionally, certain cyber incidents may remain undetected for an extended period. There can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition, results of operations or cash flows. Furthermore, the growth of cyber attacks has resulted in evolving legal and compliance matters which impose significant costs that are likely to increase over time.

We emerged from bankruptcy in September 2016, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our emergence could adversely affect our business and relationships with customers, employees and suppliers. Due to uncertainties, many risks exist, including the following:

- key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- our ability to renew existing contracts and compete for new business may be adversely affected;
- our ability to attract, motivate and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities;
- our ability to obtain credit and raise capital on terms acceptable to us or at all; and
- our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the plan of reorganization and the transactions contemplated thereby and our adoption of fresh start accounting and the full cost method of accounting for oil and gas properties.

Upon our emergence from bankruptcy, we adopted Fresh Start Accounting and the full cost method of accounting for oil and gas properties. Accordingly, our financial condition and results of operations after September 2016 may not be comparable to the financial condition or results of operations reflected in the Predecessor's historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock. The adoption of Fresh Start Accounting established a new basis for our assets and liabilities on the Emergence Date. The adoption of the full cost method of accounting for oil and gas properties, as compared to the successful efforts method utilized by the Predecessor, results in the capitalization of additional costs as well as different methodologies to determine depletive write-offs and impairments. For a more detailed discussion of Fresh Start Accounting and the full cost method of accounting for oil and gas properties, see the discussion of "Critical Accounting Estimates" included in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" as well as Notes 3, 4 and 8 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Certain provisions of our certificate of incorporation and our bylaws may make it difficult for stockholders to change the composition of our Board and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of our Certificate of Incorporation and our Bylaws may have the effect of delaying or preventing changes in control if our Board determines that such changes in control are not in the best interests of the Company and our stockholders. The provisions in our Certificate of Incorporation and Bylaws include, among other things, those that:

- authorize our Board to issue preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval;
- establish advance notice procedures for nominating directors or presenting matters at stockholder meetings; and
- limit the persons who may call special meetings of stockholders.

While these provisions have the effect of encouraging persons seeking to acquire control of the Company to negotiate with our Board, they could enable the Board to hinder or frustrate a transaction that some, or a majority, of the stockholders may believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors. These provisions may frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our Board, which is responsible for appointing the members of our management.

The market price of our common stock is subject to volatility.

The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading of our common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our limited trading volume, the concentration of holdings of our common stock, the lack of comparable historical financial information due to our adoption of Fresh Start Accounting and the full cost method of accounting for oil and gas properties, actual or anticipated variations in our operating results and cash flow, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results, including those described in this report. The pending

Merger may also cause volatility in the trading of our common stock. Significant sales of our common stock, or the expectation of these sales, by significant shareholders, officers or directors could materially and adversely affect the market price of our common stock.

Our business and the trading prices of our securities could be negatively affected as a result of actions of so-called "activist" shareholders, and such activism could impact the trading value of our securities.

Shareholders may from time to time attempt to effect changes, engage in proxy solicitations or advance shareholder proposals. Activist shareholders may make strategic proposals, suggestions or requested changes concerning our operations, strategy, management, assets or other matters. If we become the subject of activity by activist shareholders, responding to such actions could be costly and time-consuming, diverting the attention of our management and employees. Furthermore, activist campaigns can create perceived uncertainties as to our future direction, strategy, or leadership and may result in the loss of potential business opportunities and cause our stock price to experience periods of volatility.

There may be future sales or other dilution of our equity, which may adversely affect the market price of our common stock.

We are not restricted from issuing additional common stock, including securities that are convertible into or exchangeable for, or that represent a right to receive, common stock. Any issuance of additional shares of our common stock or convertible securities will dilute the ownership interest of our common stockholders. Sales of a substantial number of shares of our common stock or other equity-related securities in the public market, or the perception that these sales could occur, could depress the market price of our common stock and impair our ability to raise capital through the sale of additional equity securities. We cannot predict the effect that future sales of our common stock or other equity-related securities would have on the market price of our common stock.

Because we have no plans to pay dividends on or repurchase our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on or repurchasing our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends or repurchase of our common stock will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions and other considerations that our board of directors deems relevant. Covenants contained in the Credit Facility and the Second Lien Facility restrict the payment of dividends and share repurchases. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

Item 1B Unresolved Staff Comments

None.

Item 2 Properties

As of December 31, 2018, our oil and gas assets were located in Gonzales, Lavaca, Fayette and Dewitt Counties in South Texas.

Facilities

Our corporate headquarters and field office facilities are leased and we believe that they are adequate for our current needs.

Title to Oil and Gas Properties

Prior to completing an acquisition of producing oil and gas assets, we review title opinions on all material leases. As is customary in the oil and gas industry, however, we make a cursory review of title when we acquire farmout acreage or undeveloped oil and gas leases. Prior to the commencement of drilling operations, a thorough title examination is conducted. To the extent the title examination reflects defects, we cure such title defects. If we are unable to cure any title defect of a nature such that it would not be prudent to commence drilling operations on a property, we could suffer a loss of our investment in the property. Our oil and gas properties are subject to customary royalty interests, liens for debt obligations, current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties. We believe that we have satisfactory title to all of our properties and the associated oil and gas in accordance with standards generally accepted in the oil and gas industry.

Summary of Oil and Gas Reserves

Proved Reserves

The following tables summarize certain information regarding our estimated proved reserves as of December 31 for each of the years presented:

	Crude Oil	NGLs	Natural Gas	Oil Equivalents	Standardized Measure	PV10 [1]
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	$ in millions	$ in millions
2018						
Developed						
Producing	35.2	6.3	31.8	46.8		
Non-producing	—	—	—	—		
	35.2	6.3	31.8	46.8		
Undeveloped	54.5	11.7	59.7	76.2		
	89.7	18.0	91.5	123.0	$ 1,623.9	$ 1,769.4
Price measurement used	$65.56/Bbl	$23.60/Bbl	$3.10/MMBtu			
2017						
Developed						
Producing	22.4	4.9	27.2	31.8		
Non-producing	—	—	—	—		
	22.4	4.9	27.2	31.8		
Undeveloped	33.4	4.0	20.1	40.8		
	55.8	8.9	47.3	72.6	$ 590.5	$ 609.0
Price measurement used	$51.34/Bbl	$18.48/Bbl	$2.98/MMBtu			
2016						
Developed						
Producing	17.5	4.3	24.8	25.9		
Non-producing	0.2	0.1	0.1	0.3		
	17.7	4.4	24.9	26.2		
Undeveloped	18.9	2.4	11.8	23.3		
	36.6	6.8	36.7	49.5	$ 317.5	$ 317.5
Price measurement used	$42.75/Bbl	$12.33/Bbl	$2.48/MMBtu			

[1] PV10 represents a non-GAAP measure that is most directly comparable to the Standardized Measure as defined in GAAP. The Standardized Measure represents the discounted future net cash flows from our proved reserves after future income taxes discounted at 10% in accordance with SEC criteria. PV10 represents the Standardized Measure without regard to income taxes. Our Standardized Measures for 2016 did not include any income tax effect. Accordingly, our PV10 and Standardized Measure values were equivalent as of that date. We believe that PV10 is a meaningful supplemental disclosure to the Standardized Measure as the PV10 concept is widely used within the industry and by the financial and investment community to evaluate the proved reserves on a comparable basis across companies without regard to the individual owner's unique income tax position. We utilize PV10 to evaluate the potential return on investment in our oil and gas properties as well as evaluating properties for potential purchases and sales.

A discussion and analysis of the changes in our total proved reserves is provided in "*Supplemental Information on Oil and Gas Producing Activities (Unaudited)*" included in Part II, Item 8, "Financial Statements and Supplementary Data."

Proved Undeveloped Reserves

The proved undeveloped reserves included in our reserve estimates relate to wells that are forecasted to be drilled within the next five years. The following table sets forth the changes in our proved undeveloped reserves during the year ended December 31, 2018:

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	33.4	4.0	20.1	40.8
Revisions of previous estimates	(13.9)	(1.4)	(7.2)	(16.5)
Extensions and discoveries	42.0	10.4	52.7	61.1
Purchase of reserves	3.7	0.2	1.2	4.1
Conversion to proved developed reserves	(10.7)	(1.4)	(7.1)	(13.3)
Proved undeveloped reserves at end of year	54.5	11.8	59.7	76.2

In 2018, our proved undeveloped reserves increased by 35.4 MMBOE. The overall increase over our proved undeveloped reserves at the end of 2017 is due primarily to a significant shift in our development plans from the northwest portion of our acreage position in the Eagle Ford to the southeast region. The performance of our wells drilled in the southeast region in the first half of the year was the impetus to our redirecting of resources and replication, to the extent practical, of our drilling and completion design techniques for the second half of 2018. Of the 53 gross wells we drilled in 2018, 19 gross wells were not proved undeveloped locations at the end of 2017. Accordingly, our five-year drilling plan is currently heavily weighted to the southeast region.

The shift in focus is reflected in the changes as follows: we experienced net negative revisions of 16.5 MMBOE including: (i) 21.1 MMBOE due to the loss of certain locations resulting from changes in the drilling locations and timing attributable to our development plans as discussed above partially offset by (ii) 4.1 MMBOE due to improved treatable lateral lengths in certain locations due primarily to reconfiguration of the planned drilling units and (iii) 0.5 MMBOE of other changes, primarily price-related. Extensions and discoveries of 61.1 MMBOE are substantially attributable to geographical shift in our development plan, greater utilization of extended reach laterals, increasing the length of such laterals, higher EUR estimates per lateral foot and higher net revenue interests due to the Hunt Acquisition. We acquired 4.1 MMBOE in connection with the Hunt Acquisition. In addition, we converted 13.3 MMBOE from proved undeveloped to proved developed reserves in the Eagle Ford. During 2018, we incurred capital expenditures of $204.2 million attributable to 34 gross (28.7 net) wells in connection with the conversion of proved undeveloped reserves to proved developed reserves. While our conversion rate for proved undeveloped reserves improved to 33 percent in 2018 from 21 percent in 2017, it was nonetheless impacted by the aforementioned shift in the focus of the development plan during 2018.

Preparation of Reserves Estimates and Internal Controls

The proved reserve estimates were prepared by DeGolyer and MacNaughton, Inc., our independent third party petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see "*Supplemental Information on Oil and Gas Producing Activities (Unaudited)*" in our Notes to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" and the report of DeGolyer and MacNaughton, Inc., dated January 28, 2019, which is included as an Exhibit to this Annual Report on Form 10-K. We did not file any reports during the year ended December 31, 2018 with any federal authority or agency with respect to our estimate of oil and gas reserves.

Our policies and practices regarding the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC's regulations and GAAP. Our Vice President, Engineering is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc. Our Vice President, Engineering has over 30 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the State of Texas as a Professional Engineer. Our internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For additional information about the risks inherent in our estimates of proved reserves, see Part I, Item 1A, "Risk Factors."

Qualifications of Third Party Petroleum Engineers

The technical person primarily responsible for review of our reserve estimates at DeGolyer and MacNaughton, Inc. meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

Oil and Gas Production, Production Prices and Production Costs

In the tables that follow, we have presented our former operations in the Mid-Continent, which were sold in 2018, as "Divested properties." The sale of those operations represented a complete divestiture and we have retained no interests therein. The production associated with our former Marcellus Shale properties through August 2016 is also included within "Divested properties." Our remaining operations are exclusively represented in the Eagle Ford in South Texas.

Oil and Gas Production by Region

The following tables set forth by region our total production and average daily production for the periods presented:

	Total Production			
	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12
Region	**2018**	**2017**	**2016**	**2016**
	(MBOE)			(MBOE)
South Texas	7,780	3,487	937	3,071
Divested properties [1]	165	292	103	276
	7,944	3,779	1,039	3,346

	Average Daily Production			
	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12
Region	**2018**	**2017**	**2016**	**2016**
	(BOEPD)			(BOEPD)
South Texas	21,314	9,553	8,515	11,995
Divested properties [1]	451	800	934	1,076
	21,765	10,353	9,449	13,071

[1] Represents total production and average daily production of our former Mid-Continent operations for all periods presented and approximately 10 MBOE (48 BOEPD) for 2016 attributable to our then active Marcellus Shale wells.

Production Prices and Production Costs

The following table sets forth the average sales prices per unit of volume and our average production costs, not including ad valorem and production/severance taxes, per unit of production for the periods presented:

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12
	2018	2017	2016	2016
Average prices:				
Crude oil ($ per Bbl)	$ 66.23	$ 50.96	$ 46.68	$ 35.21
NGLs ($ per Bbl)	$ 20.99	$ 19.25	$ 16.56	$ 11.37
Natural gas ($ per Mcf)	$ 3.08	$ 2.89	$ 2.81	$ 2.06
Aggregate ($ per BOE)	$ 55.33	$ 42.20	$ 37.19	$ 27.99
Average production and lifting cost ($ per BOE):				
Lease operating	$ 4.52	$ 5.76	$ 5.13	$ 4.67
Gathering processing and transportation	2.34	2.84	2.93	3.96
	$ 6.86	$ 8.60	$ 8.06	$ 8.63

Significant Fields

Our properties in the Eagle Ford in South Texas, which contain primarily crude oil reserves, represented all of our total equivalent proved reserves as of December 31, 2018.

The following table sets forth certain information with respect to this field for the periods presented:

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12
	2018	2017	2016	2016
Production:				
Crude oil (MBbl)	6,050	2,716	695	2,265
NGLs (MBbl)	944	418	130	449
Natural gas (MMcf)	4,713	2,120	674	2,141
Total (MBOE)	7,780	3,487	937	3,071
Percent of total company production	98%	92%	90%	92%
Average prices:				
Crude oil ($ per Bbl)	$ 66.24	$ 51.08	$ 46.73	$ 35.24
NGLs ($ per Bbl)	$ 21.10	$ 18.13	$ 14.82	$ 10.34
Natural gas ($ per Mcf)	$ 3.16	$ 2.95	$ 2.79	$ 2.05
Aggregate ($ per BOE)	$ 55.99	$ 43.74	$ 38.71	$ 28.94
Average production and lifting cost ($ per BOE):				
Lease operating	$ 4.47	$ 5.79	$ 5.39	$ 4.58
Gathering processing and transportation	2.27	2.49	2.58	3.50
	$ 6.74	$ 8.28	$ 7.97	$ 8.08

Drilling and Other Exploratory and Development Activities

The following table sets forth the gross and net development wells that we drilled, all of which were in the Eagle Ford in South Texas, during the years ended December 31, 2018, 2017 and 2016, respectively, and wells that were in progress at the end of each year. There were no exploratory wells drilled in any of the years presented. The number of wells drilled refers to the number of wells completed at any time during the year, regardless of when drilling was initiated.

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	53	45.5	29	16.9	5	2.9
Dry well [1]	—	—	1	0.7	—	—
Total	53	45.5	30	17.6	5	2.9
Wells in progress at end of year [2]	11	10.2	11	8.2	5	2.6

[1] Represents the Zebra Hunter 05H well in the northern portion of our Eagle Ford acreage.
[2] Includes two gross (2.0 net) wells completing, four gross (3.8 net) wells waiting on completion and five gross (4.4 net) wells being drilled as of December 31, 2018.

Present Activities

As of December 31, 2018, we had 11 gross (10.2 net) wells in progress. As of February 22, 2019, four gross (4.0 net) wells were completing and six gross (5.4 net) wells were in process of being drilled by three operated rigs.

Delivery Commitments

We generally sell our oil, NGL and natural gas products using short-term floating price physical and spot market contracts. We have commitments to provide minimum deliveries of crude oil of 8,000 BOPD (gross) in our South Texas region through 2031 under gathering and transportation agreements with Republic Midstream, LLC, or Republic Midstream. Our production and reserves are currently sufficient to fulfill the current 8,000 BOPD delivery commitment under these agreements. In 2016, following the suspension of our drilling program, we incurred charges for deficiencies of $0.4 million as a result of our inability to satisfy the 15,000 BOPD delivery commitment under such agreements prior to their August 2016 amendments in connection with our emergence from bankruptcy.

Productive Wells

The following table sets forth our productive wells in which we had a working interest as ofDecember 31, 2018:

	Primarily Oil		Primarily Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	458	375.5	2	2.0	460	377.5

Of the total wells presented in the table above, we are the operator of 448 gross (446 oil and two natural gas) and 375.6 net (373.6 oil and 2.0 natural gas) wells. In addition to the above working interest wells, we own overriding royalty interests in 13 gross wells.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2018 (in thousands):

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Total acreage	89.9	76.9	8.3	7.3	98.2	84.2

The primary terms of our leases generally range from three to five years and we do not have any concessions. As of December 31, 2018, our net undeveloped acreage is scheduled to expire as shown in the table below, unless the primary lease terms are, where appropriate, extended, HBP or otherwise changed:

	2019	2020	2021	Thereafter
Expirations by year	0.7	5.5	0.9	0.2

We anticipate paying options to extend a substantial portion of the acreage scheduled to expire in 2019. We do not believe that the remaining scheduled expirations of our undeveloped acreage will substantially affect our ability or plans to conduct our exploration and development activities.

Item 3 Legal Proceedings

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

On August 11, 2016, the Bankruptcy Court confirmed the Plan, and we subsequently emerged from bankruptcy on September 12, 2016. On November 20, 2018, the Bankruptcy Court issued a final decree to close the case. See Note 4 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data," for a more detailed discussion of our bankruptcy proceedings and emergence.

See Note 15 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." We are not aware of any material legal or governmental proceedings against us, or threatened to be brought against us, under the various environmental protection statutes to which we are subject.

Item 4 Mine Safety Disclosures

Not applicable.

Part II

Item 5 Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Since December 28, 2016, our common stock has been listed and traded on the Nasdaq under the symbol "PVAC."

Equity Holders

As of February 19, 2019, there were 91 record holders of our common stock.

Dividends

We have not paid nor do we intend in the foreseeable future to pay any cash dividends on our common stock. Furthermore, we are restricted from paying dividends under the Credit Facility and the Second Lien Facility.

Securities Authorized for Issuance Under Equity Compensation Plans

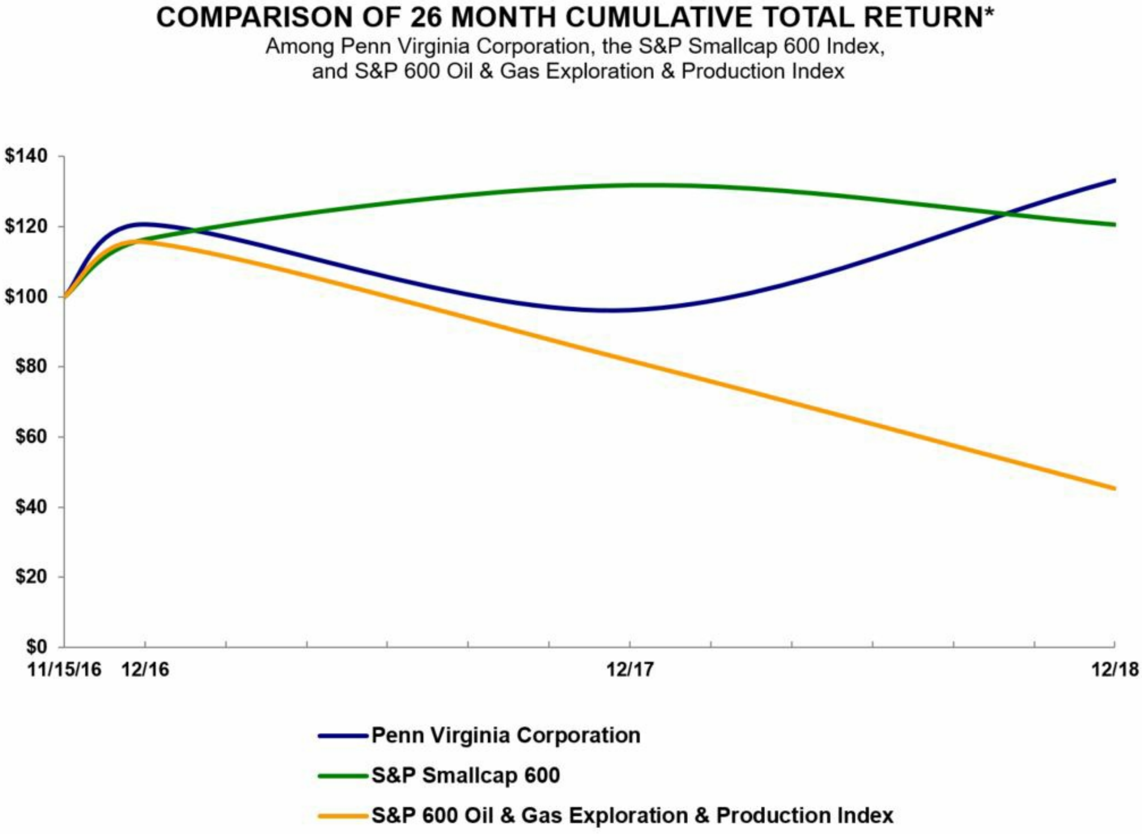
See Part III, Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" and Note 17 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for information regarding shares of common stock authorized for issuance under our stock compensation plans.

Issuer Purchases of Equity Securities

We did not repurchase any shares of our common stock in the fourth quarter of 2018.

Performance Graph

The following graph compares our cumulative total shareholder return with the cumulative total return of the Standard & Poor's 600 Oil & Gas Exploration and Production Index and the Standard & Poor's SmallCap 600 Index for the period from November 15, 2016 (the date that our common shares became publicly tradeable) through December 31, 2018. As of December 31, 2018, there were nine exploration and production companies in the Standard & Poor's 600 Oil & Gas Exploration and Production Index: Bonanza Creek Energy Inc., Carrizo Oil & Gas, Inc., Denbury Resources Inc., Gulfport Energy Corporation, Highpoint Resources Corporation, Laredo Petroleum Inc., PDC Energy Inc., Ring Energy Inc. and SRC Energy Inc. The graph assumes $100 is invested on November 15, 2016 in us and each index at November 15, 2016 closing prices.



*$100 invested on 11/15/16 in stock or 10/31/16 in index, including reinvestment of dividends.
Fiscal year ending December 31.

The following table represents the actual data points for the dates indicated on the graph above:

	November 15,	December 31,		
	2016	2016	2017	2018
Penn Virginia Corporation	$ 100.00	$ 120.62	$ 96.27	$ 133.05
S&P SmallCap 600 Index	$ 100.00	$ 116.34	$ 131.74	$ 120.56
S&P 600 Oil & Gas Exploration & Production Index	$ 100.00	$ 115.64	$ 81.84	$ 45.36

Item 6 Selected Financial Data

The following selected historical financial and operating information was derived from our Consolidated Financial Statements. The selected financial data should be read in conjunction with Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our Consolidated Financial Statements and the accompanying Notes and Supplementary Data in Part II, Item 8, "Financial Statements and Supplementary Data."

(in thousands, except per share amounts, production and reserves)	Successor			Predecessor		
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2018	2017	2016	2016	2015	2014
Statements of Operations and Other Data:						
Revenues	$ 440,832	$ 160,054	$ 39,003	$ 94,310	$ 305,298	$ 636,773
Operating income (loss)[1, 2]	$ 208,755	$ 51,872	$ 11,413	$ (20,867)	$ (1,564,976)	$ (615,920)
Net income (loss) [3]	$ 224,785	$ 32,662	$ (5,296)	$ 1,054,602	$ (1,582,961)	$ (409,592)
Preferred stock dividends [4]	$ —	$ —	$ —	$ 5,972	$ 22,789	$ 17,148
Income (loss) attributable to common shareholders	$ 224,785	$ 32,662	$ (5,296)	$ 1,048,630	$ (1,605,750)	$ (430,996)
Income (loss) per common share, basic	$ 14.93	$ 2.18	$ (0.35)	$ 11.91	$ (21.81)	$ (6.26)
Income (loss) per common share, diluted	$ 14.70	$ 2.17	$ (0.35)	$ 8.50	$ (21.81)	$ (6.26)
Weighted-average shares outstanding:						
Basic	15,059	14,996	14,992	88,013	73,639	68,887
Diluted	15,292	15,063	14,992	124,087	73,639	68,887
Dividends declared per share	$ —	$ —	$ —	$ —	$ —	$ —
Cash provided by operating activities	$ 272,132	$ 81,710	$ 30,774	$ 30,247	$ 169,303	$ 282,724
Cash paid for capital expenditures	$ 430,592	$ 115,687	$ 4,812	$ 15,359	$ 364,844	$ 774,139
Total production (MBOE)	7,944	3,779	1,039	3,346	7,923	7,934

	December 31,			September 12,	December 31,	
Balance Sheet and Other Data:	2018	2017	2016	2016	2015	2014
Property and equipment, net	$ 927,994	$ 529,059	$ 247,473	$ 253,510	$ 344,395	$ 1,825,098
Total assets	$ 1,068,954	$ 629,597	$ 291,686	$ 333,974	$ 517,725	$ 2,201,810
Total debt	$ 511,375	$ 265,267	$ 25,000	$ 75,350	$ 1,224,383	$ 1,085,429
Shareholders' equity (deficit)	$ 447,355	$ 221,639	$ 185,548	$ 190,895	$ (915,121)	$ 675,817
Actual shares outstanding at period-end	15,081	15,019	14,992	14,992	81,253	71,569
Proved reserves as of December 31, (MMBOE)	123	73	49	N/A	44	115

[1] Operating loss for 2015 and 2014 included impairment charges of $1.4 billion and $791.8 million, respectively.

[2] Operating income (loss) for all periods prior to 2018 reflects the retrospective application of Accounting Standards Update 2017–07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* or ASU 2017-07. See "*Overview and Executive Summary*" included in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 2 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[3] Net income (loss) and Income (loss) attributable to common shareholders for the year ended December 31, 2018 and the period of January 1 through September 12, 2016 includes reorganization items attributable to our bankruptcy proceedings of $3.3 million and $1.1 billion, respectively.

[4] Excludes inducements paid for the conversion of preferred stock of $4.3 million in 2014.

Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Part II, Item 8, "Financial Statements and Supplementary Data." 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 and 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 crude oil, NGLs and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford, in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

Presentation of Financial Information and Changes in Accounting Principles

Emergence from Bankruptcy

As discussed in further detail in Note 4 to our Consolidated Financial Statements, we have adopted and applied Fresh Start Accounting as a result of our emergence from bankruptcy in 2016. Accordingly, our Consolidated Financial Statements and Notes after September 12, 2016 are not comparable to the Consolidated Financial Statements and Notes prior to that date. To facilitate the discussion and analysis of our financial condition and results of operations herein, we refer to the reorganized company as the "Successor" for periods subsequent to September 12, 2016, and the "Predecessor" for periods prior to September 13, 2016. Furthermore, our presentations herein include a "black line" division to delineate the lack of comparability between the Predecessor and Successor. In order to enhance our discussion herein, we have addressed the Successor and Predecessor periods discretely and have provided comparative analysis, to the extent practical, where appropriate. In addition, and as referenced in Note 2 to the 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 and financial position for the Successor periods will be substantially different from our historic trends.

Adoption of New Accounting Standards

As discussed in further detail in Notes 2 and 6 to the Consolidated Financial Statements, we have adopted two new accounting standards: Accounting Standards Codification Topic 606, *Revenues from Contracts with Customers*, or ASC Topic 606, and ASU 2017–07, effective January 1, 2018. The adoption of these standards impacts the presentation and comparability of (i) NGL product revenues and Gathering, processing and transportation, or GPT, expense; and (ii) General and administrative, or G&A, expenses and Other income (expense), net. We adopted ASC Topic 606 utilizing the cumulative effect transition method. Accordingly, our NGL revenues and GPT expense for the year ended December 31, 2017 are not comparable to the 2018 presentation of these items. Our discussion and analysis of these items in the *Results of Operations* that follow address the effects of changes directly attributable to the adoption of ASC Topic 606. We adopted ASU 2017–07 utilizing the modified retrospective method. Accordingly, certain retiree benefits costs that were previously reported as a component of G&A are being reported as a component of Other, net (expenses), as required by ASU 2017–07, for all periods presented.

Industry Environment and Recent Operating and Financial Highlights

Crude oil prices continued rising in the second half of 2017 throughout the first half of 2018 and then declined precipitously in the fall of 2018. Global economic conditions as well as domestic supply are anticipated to maintain downward pressure on crude oil prices for the near term. Despite these challenges, we continue to benefit from the proximity of our operating region to the Gulf Coast markets whereby we sell substantially all of our crude oil production based on the Light Louisiana Sweet, or LLS, price index. The LLS index has exceeded that of the West Texas Intermediate, or WTI, price index, providing us with a strong revenue stream compared to certain of our domestic peers and competitors located at a greater distance from the Gulf Coast markets. Subsequent to 2016, domestic production has increased, including that in the broader Eagle Ford region in which we operate. This environment has expanded opportunities in our principal operating region. In addition, there has been a consolidation of holdings within the Eagle Ford, including our own, through recent acquisitions. Collectively, these and other factors have led, at times, to higher pricing for certain oilfield products and services, including drilling services. At this time we do not anticipate any significant declines in such costs for 2019.

The following summarizes certain key operating and financial highlights for the three months ended December 31, 2018 with comparison to the three months ended September 30, 2018 as presented in the table that follows. The year-over-year highlights for 2018 and 2017 are addressed in further detail in the discussions for *Financial Condition* and *Results of Operations* that follow.

- Production increased approximately 12 percent to 2,363 MBOE, from 2,108 MBOE due primarily to incremental production from the 10 gross (8.9 net) wells turned to sales during the quarter, the majority of which were turned to sales in the first month of the quarter.
- Product revenues decreased approximately two percent to $124.6 million from $126.8 million due primarily to approximately $18.0 million of which relates to 14 percent and three percent lower crude oil and NGL pricing, partially offset by $14.7 million due to the effect of higher overall production volume, and $1.1 million from 26 percent higher natural gas pricing.
- Production and lifting costs, which include LOE and GPT, increased on an absolute basis to $15.7 million from $14.8 million, but decreased on a per unit basis to $6.65 per BOE, from $7.04 per BOE due primarily to lower surface maintenance costs as well as the effect of the increase in production volume.
- Production and ad valorem taxes decreased on an absolute and per unit basis to $6.5 million and $2.75 per BOE from $7.2 million and $3.39 per BOE, respectively, due primarily to lower crude oil and NGL pricing partially offset by the effect of higher production volume.
- General and administrative expenses increased on an absolute and per unit basis to $8.1 million and $3.43 per BOE from $6.2 million and $2.92 per BOE, respectively, due primarily to transaction costs associated with the Merger partially offset by the effect of higher production volume.
- Our DD&A increased to $39.6 million, or $16.75 per BOE from $35.0 million, or $16.61 per BOE due primarily to $4.2 million from the effect of higher production volume, as well as $0.4 million attributable to the effect of higher rates, resulting from higher capitalized costs for oil and gas properties.
- Our operating income declined to $54.9 million from $64.0 million due to the combined impact of the matters noted in the bullets above.

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

	(in thousands except per unit measurements, production, wells and reserves)					
	Successor					Predecessor
					September 13 Through	January 1 Through
	Three Months Ended		Year Ended December 31,		December 31,	September 12,
	December 31, 2018	September 30, 2018	2018	2017	2016	2016
Total production (MBOE)	2,363	2,108	7,944	3,779	1,039	3,346
Average daily production (BOEPD)	25,686	22,912	21,765	10,353	9,449	13,071
Crude oil production (MBbl)	1,818	1,633	6,077	2,764	710	2,311
Crude oil production as a percent of total	77%	77%	76%	73%	68%	69%
Product revenues	$ 124,572	$ 126,803	$ 439,530	$ 159,469	$ 38,654	$ 93,649
Crude oil revenues	$ 112,452	$ 117,059	$ 402,485	$ 140,886	$ 33,157	$ 81,377
Crude oil revenues as a percent of total	90%	92%	92%	88%	86%	87%
Realized prices:						
Crude oil ($ per Bbl)	$ 61.84	$ 71.67	$ 66.23	$ 50.96	$ 46.68	$ 35.21
NGL ($ per Bbl) [1]	$ 21.79	$ 22.41	$ 20.99	$ 19.25	$ 16.56	$ 11.37
Natural gas ($ per Mcf)	$ 3.80	$ 3.02	$ 3.08	$ 2.89	$ 2.81	$ 2.06
Aggregate ($ per BOE)	$ 52.72	$ 60.16	$ 55.33	$ 42.20	$ 37.19	$ 27.99
Prices, adjusted for derivatives::						
Crude oil ($ per Bbl)	$ 54.64	$ 62.36	$ 58.28	$ 49.69	$ 47.22	$ 55.98
Aggregate ($ per BOE)	$ 47.17	$ 52.94	$ 49.25	$ 41.27	$ 37.56	$ 42.33
Production and lifting costs ($ per BOE):						
Lease operating	$ 4.21	$ 4.70	$ 4.52	$ 5.76	$ 5.13	$ 4.67
Gathering, processing and transportation [1]	$ 2.44	$ 2.34	$ 2.34	$ 2.84	$ 2.93	$ 3.96
Production and ad valorem taxes ($ per BOE)	$ 2.75	$ 3.39	$ 2.96	$ 2.33	$ 2.40	$ 1.04
General and administrative ($ per BOE) [2]	$ 3.43	$ 2.92	$ 3.28	$ 4.82	$ 4.88	$ 11.64
Depreciation, depletion and amortization ($ per BOE) [3]	$ 16.75	$ 16.61	$ 16.11	$ 12.87	$ 11.21	$ 10.04
Capital expenditure program costs [4]	$ 105,099	$ 104,589	$ 418,951	$ 129,827	$ 5,454	$ 4,113
Cash provided by operating activities [5]	$ 79,227	$ 72,487	$ 272,132	$ 81,710	$ 30,774	$ 30,247
Cash paid for capital expenditures [6]	$ 107,333	$ 121,909	$ 430,592	$ 115,687	$ 4,812	$ 15,359
Cash and cash equivalents at end of period	$ 17,864	$ 8,011	$ 17,864	$ 11,017	$ 6,761	$ 31,414
Debt outstanding, net of discount and issue costs, at end of period	$ 511,375	$ 472,344	$ 511,375	$ 265,267	$ 25,000	$ 75,350
Credit available under credit facility at end of period	$ 128,600	$ 57,100	$ 128,600	$ 159,745	$ 102,233	$ 51,883
Net development wells drilled and completed	8.9	9.7	45.5	16.9	—	2.9
Proved reserves at the end of the period (MMBOE)	123	N/A	123	73	49	N/A

[1] The effects of the adoption of ASC Topic 606, if applied to the three months ended December 31, 2017 and the year ended December 31, 2017, would have resulted in realized prices for NGLs of $19.27 and $16.40 per BOE and GPT of $2.43 and $2.45 per BOE, respectively.

[2] Includes combined amounts of $1.56 and $0.51 per BOE for the three months ended December 31, 2018 and September 30, 2018, respectively, and $1.11 , $1.36 and $6.98 per BOE for the Successor periods ended December 31, 2018 and 2017 and the Predecessor period in 2016, respectively, attributable to equity- and liability-classified share-based compensation and significant special charges, including acquisition, divestiture and strategic transaction costs and strategic and financial advisory costs prior to our bankruptcy filing, among others costs, as described in the discussion of "*Results of Operations - General and Administrative* " that follows.

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

[4] Includes amounts accrued and excludes capitalized interest and capitalized labor.

[5] Includes net cash paid for derivative settlements of $13.1 million and $15.2 million for the three months ended December 31, 2018 and September 30, 2018, respectively, and $48.3 million and $3.5 million for the years ended December 31, 2018 and 2017, respectively, and cash received from derivative settlements of $0.4 million and $48.0 million for the Successor and Predecessor periods ended in 2016, respectively. Reflects changes in operating assets and liabilities of $(0.7) million and $(6.1) million for the three months ended December 31, 2018 and September 30, 2018, respectively, and $(2.8) million, $(15.0) million and $7.0 million for the Successor periods ended December 31, 2018, 2017 and 2016 and $35.2 million for the Predecessor period in 2016, respectively.

[6] Represents actual cash paid for capital expenditures including capitalized interest and capitalized labor.

Key Developments

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

Merger with Denbury

On October 28, 2018, Denbury and Penn Virginia announced the Merger in which Denbury will acquire Penn Virginia. The consideration to be paid to Penn Virginia shareholders will consist of 12.4 shares of Denbury common stock and $25.86 of cash for each share of Penn Virginia common stock. Penn Virginia shareholders will be permitted to elect to receive either all cash, all stock or a mix of stock and cash, in each case subject to proration, which will result in the aggregate issuance by Denbury of approximately 191.667 million Denbury shares and payment by Denbury of $400 million in cash. The transaction was unanimously approved by the board of directors of each company, and certain Penn Virginia shareholders holding approximately 15 percent of the outstanding shares signed voting agreements to vote "for" the transaction. The transaction is subject to the approval by the holders of more than two-thirds of the outstanding Company common shares, the approval by the holders of a majority of the outstanding Denbury common shares of an amendment to the certificate of incorporation to increase the number of authorized Denbury common shares, the approval of the issuance of Denbury common shares in the Merger by the holders of a majority of the Denbury common shares represented in person or by proxy at a meeting of Denbury shareholders held to vote on such matter and other customary closing conditions. The special meeting of shareholders to approve the merger is anticipated in April 2019 and closing is anticipated soon thereafter, subject to shareholder approval and certain other conditions. The Merger Agreement contains certain termination rights for both Denbury and the Company, including if the Merger is not consummated by April 30, 2019, and requires Penn Virginia to pay a $45 million termination fee in certain circumstances.

Production and Development Plans

Total production for the quarter and year ended December 31, 2018 was 2,363 MBOE and 7,944, or 25,686 and 21,765 BOEPD, with approximately 77 percent and 76 percent, or 1,818 MBbls and 6,077 MBbls, of production from crude oil, 13 percent from NGLs for each period and 10 percent and 11 percent from natural gas. Production from our Eagle Ford operations during the annual period was 7,780 MBOE or 21,314 BOEPD while all of our production was derived from this region during the fourth quarter of 2018 following the sale of our Mid-Continent operations in July of 2018.

We drilled and turned 10 and 53 gross (8.9 and 45.5 net) Eagle Ford wells to sales during the quarter and year ended December 31, 2018, respectively. Subsequent to December 31, 2018, we drilled and turned an additional four gross (2.9 net) wells to sales. As of February 22, 2019, we were in the process of drilling six gross (5.4 net) wells with our three operated drilling rigs and four gross (4.0 net) wells were completing.

As of December 31, 2018, we had approximately 98,200 gross (84,200 net) acres in the Eagle Ford, net of expirations. Approximately 92 percent of our acreage is held by production and substantially all is operated by us.

Amendment to Credit Facility

In October 2018, we entered into the Borrowing Base Agreement and Amendment No. 5 to the Credit Facility, or the Fifth Amendment, to our credit agreement, or Credit Facility, increasing the borrowing base from $340.0 million to $450.0 million, among other things.

Acquisition of Producing Properties

In December 2017, we entered into a purchase and sale agreement with Hunt, to acquire certain oil and gas assets in the Eagle Ford Shale, primarily in Gonzales and Lavaca Counties, Texas for $86.0 million in cash, subject to adjustments, or the Hunt Acquisition. The Hunt Acquisition had an effective date of October 1, 2017, and closed on March 1, 2018, at which time we paid cash consideration of $84.4 million. We received $1.4 million from Hunt, primarily attributable to suspended revenues, in a final settlement that occurred in July 2018. In connection with the Hunt Acquisition, we also acquired working interests in certain wells that we previously drilled as operator, and in which Hunt had rights to participate prior to the transaction closing. Accumulated costs, net of suspended revenues for these wells was $13.8 million, which we have reflected as a component of the total net assets acquired. The Hunt Acquisition expanded our net leasehold position by approximately 9,700 net acres, substantially all of which is held by production, in the northwestern portion of our Eagle Ford acreage.

Commodity Hedging Program

As of February 22, 2019, we have hedged a portion of our estimated future crude oil production through the end of 2020 with a mix of WTI- and LLS- indexed swaps. We are currently unhedged with respect to NGL and natural gas production. The following table summarizes our hedge positions for the periods presented:

	WTI Volumes	WTI Average Swap Price	LLS Volumes	LLS Average Swap Price
	(Barrels per day)	($ per barrel)	(Barrels per day)	($ per barrel)
Remainder of 2019	6,407	$ 54.49	5,000	$ 59.17
2020	6,000	$ 54.09	—	—

Divestiture of Mid-Continent Properties

In June 2018, we entered into a purchase and sale agreement with a third party to sell all of our remaining Mid-Continent oil and gas properties, located primarily in Oklahoma in the Granite Wash, for $6 million in cash, subject to customary adjustments. The sale had an effective date of March 1, 2018, and closed on July 31, 2018, and we received proceeds of $6.2 million. In November 2018, we paid $0.5 million, including $0.2 million of suspended revenues, to the buyer in connection with the final settlement.

Financial Condition

Liquidity

Our primary sources of liquidity include our cash on hand, cash provided by operating activities and borrowings under the Credit Facility. The Credit Facility provides us with up to $450 million in borrowing commitments. The current borrowing base under the Credit Facility is also $450 million. As of February 22, 2019, we had $136.6 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 financial 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 derivative contracts hedging a portion of our estimated future crude oil production through the end of 2020.

Capital Resources

We plan to fund our 2019 capital spending primarily with cash from operating activities and, to the extent necessary, borrowings under the Credit Facility. Based upon current price and production expectations for 2019, we believe that our cash from operating activities and borrowings under our Credit Facility will be sufficient to fund our operations through year-end 2019; 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. For a detailed analysis of our historical capital expenditures, see the "*Cash Flows*" discussion that follows.

Cash on Hand and Cash From Operating Activities. As of February 22, 2019, we had approximately $14 million of cash on hand. For additional information and an analysis of our historical cash flows from operating activities, see the "*Cash Flows*" discussion that follows.

Credit Facility Borrowings. During 2018, we borrowed $244 million, under the Credit Facility. 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 periods presented:

	Borrowings Outstanding		
	Weighted-Average	Maximum	Weighted-Average Rate
Three months ended December 31, 2018	$ 305,217	$ 321,000	6.25%
Year ended December 31, 2018	$ 230,934	$ 321,000	5.76%

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, including the sale in 2018 of our Mid-Continent properties, see the "*Cash Flows*" discussion that follows.

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

Cash Flows

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cash flows from operating activities		
Operating cash flows, net of working capital changes	$ 346,780	$ 91,365
Crude oil derivative settlements paid, net	(48,291)	(3,511)
Interest payments, net of amounts capitalized	(22,599)	(4,102)
Acquisition, divestiture and strategic transaction costs paid	(2,968)	(1,088)
Reorganization items paid, net	(540)	(954)
Consulting costs paid to former Executive Chairman	(250)	—
Net cash provided by operating activities	272,132	81,710
Cash flows from investing activities		
Acquisitions, net	(85,387)	(200,849)
Capital expenditures	(430,592)	(115,687)
Proceeds from sales of assets, net	7,683	869
Net cash used in investing activities	(508,296)	(315,667)
Cash flows from financing activities		
Proceeds from credit facility borrowings, net	244,000	52,000
Proceeds from second lien facility, net	—	196,000
Debt issuance costs paid	(989)	(9,787)
Proceeds from rights offering, net	—	55
Other, net	—	(55)
Net cash provided by financing activities	243,011	238,213
Net increase in cash and cash equivalents	$ 6,847	$ 4,256

Cash Flows from Operating Activities. The increase in net cash from operating activities for 2018 compared to 2017 was primarily attributable to: (i) higher overall production volume in 2018, (ii) incremental net operating cash inflows from the Hunt Acquisition and the 2017 acquisition of oil and gas assets from Devon Energy Corporation, or the Devon Acquisition, (iii) higher overall product pricing in 2018 and (iv) lower payments in 2018 for bankruptcy-related administration costs as the case was closed in November 2018. These items were partially offset by: (i) substantially higher settlements paid for crude oil derivatives, (ii) higher interest payments due to greater outstanding borrowings in 2018, (iii) higher payments for acquisition, divestiture and strategic transaction costs in 2018 and (iv) certain costs paid in connection with the retirement of our Executive Chairman in February 2018.

Cash Flows from Investing Activities. In 2018, we paid a combined total of $86.5 million for the Hunt Acquisition and the purchase of other working interests in producing properties in the Eagle Ford and received a total of $1.1 million in connection with the final settlement of the Devon Acquisition. In 2017, we paid a total of $200.8 million for the preliminary settlement of the Devon Acquisition which included $0.7 million paid to other parties that had tag-along rights to sell their interests. As illustrated in the tables below, our cash payments for capital expenditures were higher during 2018 as compared to 2017 due primarily to an increase to a three-rig and two frac spread development program from a two-rig and single frac spread program in 2017 as well as the effect of higher working interests from the Hunt and Devon Acquisitions. The increased capital expenditures for 2018 and 2017 were partially offset by proceeds from asset sales during each year. We received proceeds of $7.7 million in 2018 attributable to the sales of: (i) all of our Mid-Continent properties, (ii) undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana, (iii) certain undeveloped leasehold rights in Oklahoma, (iv) certain pipeline assets in our former Marcellus Shale operating region and (v) scrap and surplus tubular and well materials. In 2017, we received proceeds of $0.9 million from the sale of certain inactive acreage in Oklahoma.

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Drilling and completion	$ 405,677	$ 125,235
Lease acquisitions and other land-related costs	5,180	4,493
Geological, geophysical (seismic) and delay rental costs	377	696
Pipeline, gathering facilities and other equipment, net	7,717	(597)
	$ 418,951	$ 129,827

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Total capital program costs (from above)	$ 418,951	$ 129,827
Increase in accrued capitalized costs	(44)	(19,910)
Less:		
Transfers from tubular inventory and well materials	(10,056)	(3,326)
Sales & use tax refunds received and applied to property accounts	(643)	(2,265)
Add:		
Tubular inventory and well materials purchased in advance of drilling	9,578	6,252
Capitalized internal labor	3,688	2,384
Capitalized interest	9,118	2,725
Total cash paid for capital expenditures	$ 430,592	$ 115,687

Cash Flows from Financing Activities. During 2018 we borrowed $244 million under the Credit Facility to fund the three-rig capital program and the Hunt Acquisition, while 2017 only included borrowings of $52 million, net of repayments. In 2017, we received proceeds of $196 million from the $200 million Second Lien Facility, or Second Lien Facility, net of OID, primarily to fund the Devon Acquisition. We also paid approximately $1.0 million of debt issuance costs in 2018 in connection with amendments to the Credit Facility and other costs in connection with the Second Lien Facility compared to $9.8 million paid in 2017 in connection with an amendments to the Credit Facility and the issuance of the Second Lien Facility. The receipt in the 2017 period of delayed proceeds attributable to the rights offering in September 2016 were fully offset by costs paid in connection with the registration of our common stock in 2017.

Capitalization

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

	December 31, 2018	December 31, 2017
Credit Facility borrowings	$ 321,000	$ 77,000
Second Lien Facility term loans, net of original issue discount and issuance costs	190,375	188,267
Total debt	511,375	265,267
Shareholders’ equity	447,355	221,639
Total capitalization	$ 958,730	$ 486,906
Debt as a % of total capitalization	53%	54%

Credit Facility. The Credit Facility provides for a $450 million revolving commitment and borrowing base. The Credit Facility includes a $5.0 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 redetermined semi-annually, generally in April and October of each year. Additionally, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us for general corporate purposes including working capital. The Credit Facility matures in September

2020. We had $0.4 million and $0.8 million in letters of credit outstanding as of December, 2018 and December 31, 2017, respectively.

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 December 31, 2018, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 5.96%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by us 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. There are no significant restrictions on our ability 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.

Second Lien Facility. On September 29, 2017, we entered into the $200 million Second Lien Facility. The maturity date under the Second Lien Facility is September 29, 2022.

The outstanding borrowings under the Second Lien Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate based on the prime rate plus an applicable margin of 6.00% or (b) a customary LIBOR rate plus an applicable margin of 7.00%. Amounts under the Second Lien Facility were borrowed at a price of 98% with an initial interest rate of 8.34% resulting in an effective interest rate of 9.89%. As of December 31, 2018, the actual interest rate on the Second Lien Facility was 9.53%. 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 eurocurrency borrowings is payable every one or three months (including in three month intervals if we select a six month interest period), at our election and is computed on the basis of a year of 360 days. We have the right, to the extent permitted under the Credit Facility and an intercreditor agreement between the lenders under the Credit Facility and the lenders under the Second Lien Facility, to prepay loans under the Second Lien Facility at any time, subject to the following prepayment premiums (in addition to customary “breakage” costs with respect to eurocurrency loans): during year one, a customary “make-whole” premium; during year two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium. The Second Lien Facility also provides for the following prepayment premiums in the event of a change in control that results in an offer of prepayment that is accepted by the lenders under the Second Lien Facility. During years one and two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of the Company’s and its subsidiaries’ assets with lien priority subordinated to the liens securing the Credit Facility. The obligations under the Second Lien Facility are guaranteed by us and the Guarantor Subsidiaries.

Covenant Compliance. The Credit Facility requires us to maintain (1) a minimum interest coverage ratio (adjusted EBITDAX, as defined in the Credit Facility, 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, as defined in the Credit Facility), measured as of the last day of each fiscal quarter, of 3.50 to 1.00. The Second Lien Facility has no financial covenants.

The Credit Facility and Second Lien Facility also contain 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 and Second Lien Facility contain customary events of default and remedies. If we do not comply with the financial and other covenants in the Credit Facility and Second Lien Facility, the lenders thereto may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility and Second Lien Facility.

As of December 31, 2018, we were in compliance with all of the covenants under the Credit Facility and the Second Lien Facility.

Results of Operations

The tabular presentations included below reflect the results of operations associated with the Successor periods of 2018, 2017 and 2016 (the period from September 13 through December 31, 2016) and the Predecessor period of 2016 (the period from January 1 through September 12, 2016). As discussed previously in "*Overview and Executive Summary*," the adoption of Fresh Start Accounting and the full cost method of accounting for oil and gas properties on the Emergence Date 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 and 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 calendar years 2018, 2017 and 2016 without regard to the concept of a Successor and Predecessor facilitates a meaningful analysis of our results of operations.

A portion of the components of our year-over-year variances for 2018 to 2017 are due to the effects of the Hunt Acquisition in March 2018 and the Devon Acquisition in September 2017. Partially offsetting the impact these transactions are the effects of our property divestitures. In the discussion and analysis that follows, the term "Divested properties" refers to the production, revenues and expenses associated with our former assets in the Mid-Continent region that we sold in July 2018 as well as former operations in the Marcellus Shale in Pennsylvania. We terminated operations in that region in August 2016 and completed well-plugging and remediation activities in 2017.

As discussed previously in "*Overview and Executive Summary*," the adoption of ASC Topic 606 and ASU 2017–07 effective January 1, 2018 impacts the presentation and comparability of (i) NGL product revenues and GPT expense; and (ii) G&A expenses and Other income (expense), net. Because we adopted ASC Topic 606 using the cumulative effect transition method, we are precluded from changing the presentation of impacted items, which include NGL product revenues and GPT expenses, in prior periods. Accordingly, the presentation of NGL product revenues and GPT expenses for 2018 are not comparable to those presented for 2017 and the Successor and Predecessor periods in 2016 (see Note 6 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data.") Conversely, the adoption of ASU 2017–07, which applies to the presentation of the components of retiree pension and postretirement benefits costs, was applied on a retrospective basis to all prior periods. Accordingly, the presentations of our G&A expenses and Other income (expense), net are comparable for all periods presented.

Production

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

	Total Production			
	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Crude oil (MBbl)	6,077	2,764	710	2,311
NGLs (MBbl)	1,004	523	164	533
Natural gas (MMcf)	5,181	2,949	994	3,012
Total (MBOE)	7,944	3,779	1,039	3,346
2018 vs 2017 Variance (MBOE)		4,165		
% Change		110 %		
2017 vs. Combined 2016 Variance (MBOE)				(606)
% Change				(14)%
	Average Daily Production			
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Crude oil (Bbl per day)	16,650	7,573	6,457	9,028
NGLs (Bbl per day)	2,750	1,432	1,486	2,083
Natural gas (MMcf per day)	14	8	9	12
Total (BOEPD)	21,765	10,353	9,449	13,071
2018 vs 2017 Variance (BOEPD)		11,412		
% Change		110 %		
2017 vs. Combined 2016 Variance (BOEPD)				(1,631)
% Change				(14)%
	Total Production by Region			
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
South Texas	7,780	3,487	937	3,071
Divested properties [1]	165	292	103	276
Total (MBOE)	7,944	3,779	1,039	3,346
2018 vs 2017 Variance (MBOE)		4,165		
% Change		110 %		
2017 vs. Combined 2016 Variance (MBOE)				(606)
% Change				(14)%
	Average Daily Production by Region			
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
South Texas	21,314	9,553	8,515	11,995
Divested properties [1]	451	800	934	1,076
Total (BOEPD)	21,765	10,353	9,449	13,071
2018 vs 2017 Variance (BOEPD)		11.412		
% Change		110 %		
2017 vs. Combined 2016 Variance (BOEPD)				(1,631)
% Change				(14)%

[1] Represents total production and average daily production of our former Mid-Continent operations for all periods presented and approximately 10 MBOE (48 BOEPD) for Predecessor period in 2016 attributable to our three then-active Marcellus Shale wells.

2018 vs. 2017. Total production increased during 2018 compared to 2017 due primarily to a greater number of wells turned to sales in 2018 under our expanded drilling program as well as incremental production from the Hunt and Devon Acquisitions. We operated three drilling rigs during 2018 compared to two during 2017, the second of which was not contracted until mid-March 2017. These increases were partially offset by the effect of the divestiture in July 2018 of our former Mid-Continent operations, as well as natural production declines from our legacy Eagle Ford wells.

Approximately 76 percent of total production during 2018 was attributable to crude oil when compared to approximately 73 percent during 2017. Our Eagle Ford production represented 98 percent of our total production during 2018 compared to approximately 92 percent from this region during 2017. Subsequent to the sale of our Mid-Continent properties on July 31, 2018, the entirety of our production was derived from the Eagle Ford. During 2018, we turned 53 gross (45.5 net) Eagle Ford wells to sales compared to 29 gross (16.9 net) wells during 2017.

2017 vs. 2016. Total production decreased during 2017 compared to the combined Successor and Predecessor periods in 2016 due primarily to natural production declines and the carryover effect from the suspension of our drilling program that began in February 2016 and extended through November 2016. While we resumed the drilling program at the end of 2016, we did not turn any new wells to sales until mid-February 2017. The decline was further exacerbated by mechanical issues with our previously-contracted drilling rigs and the effects of Hurricane Harvey in August 2017 which resulted in a partial curtailment of production for several days as well as delays in our scheduled drilling and completion activities in South Texas. Approximately 73 percent of total production during 2017 was attributable to crude oil when compared to approximately 69 percent during the combined Successor and Predecessor periods in 2016. Our Eagle Ford production represented 92 percent of our total production during 2017 compared to approximately 91 percent from this region during the combined Successor and Predecessor periods in 2016. During 2017, we turned 29 gross (16.9 net) Eagle Ford wells to sales compared to five gross (2.9 net) wells during the combined Successor and Predecessor periods in 2016.

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			
	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Crude oil	$ 402,485	$ 140,886	$ 33,157	$ 81,377
NGLs	21,073	10,066	2,707	6,064
Natural gas	15,972	8,517	2,790	6,208
Total	$ 439,530	$ 159,469	$ 38,654	$ 93,649
2018 vs. 2017 Variance		$ 280,061		
% Change		176%		
2017 vs. Combined 2016 Variance				$ 27,166
% Change				21%

	Product Revenues per Unit of Volume			
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Crude oil ($ per barrel)	$ 66.23	$ 50.96	$ 46.68	$ 35.21
NGLs ($ per barrel)	$ 20.99	$ 19.25	$ 16.56	$ 11.37
Natural gas ($ per Mcf)	$ 3.08	$ 2.89	$ 2.81	$ 2.06
Total ($ per BOE)	$ 55.33	$ 42.20	$ 37.19	$ 27.99
2018 vs. 2017 Variance ($ per BOE)		$ 13.13		
% Change		31%		
2017 vs. Combined 2016 Variance ($ per BOE)				$ 12.03
% Change				40%

	Product Revenues by Region			
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
South Texas	$ 435,599	$ 152,521	$ 36,261	$ 88,849
Divested properties [1]	3,931	6,948	2,393	4,800
Total	$ 439,530	$ 159,469	$ 38,654	$ 93,649
2018 vs. 2017 Variance		$ 280,061		
% Change		176%		
2017 vs. Combined 2016 Variance				$ 27,166
% Change				21%

	Product Revenues per BOE by Region			
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
South Texas	$ 55.99	$ 43.74	$ 38.71	$ 28.94
Divested properties [1]	$ 23.87	$ 23.79	$ 23.29	$ 17.42
Total ($ per BOE)	$ 55.33	$ 42.20	$ 37.19	$ 27.99
2018 vs. 2017 Variance ($ per BOE)		$ 13.13		
% Change		31%		
2017 vs. Combined 2016 Variance ($ per BOE)				$ 12.03
% Change				40%

[1] Represents revenues of our former Mid-Continent operations for all periods presented and $0.1 million attributable to the Marcellus Shale for the Predecessor period in 2016.

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

	Year Ended December 31, 2018 vs. Year Ended December 31, 2017			Year Ended December 31, 2017 vs. Combined Successor and Predecessor Periods Ended December 31, 2016		
	Revenue Variance Due to			Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ 168,812	$ 92,787	$ 261,599	$ (9,742)	$ 36,094	$ 26,352
NGLs	9,259	1,748	11,007	(2,188)	3,483	1,295
Natural gas	6,448	1,007	7,455	(2,378)	1,897	(481)
	$ 184,519	$ 95,542	$ 280,061	$ (14,308)	$ 41,474	$ 27,166

2018 vs. 2017. Our product revenues during 2018 increased over 2017 due primarily to approximately 120 percent higher crude oil volumes, 92 percent higher NGL volumes and 76 higher natural gas volumes as well as the effect of 30 percent higher crude oil prices and approximately seven percent higher natural gas prices. Our Eagle Ford crude oil production benefits from pricing based on the LLS index which has averaged approximately eight percent higher than the comparable WTI index during the year ended in 2018 compared to 2017. Excluding the $2.4 million effect of the adoption of ASC Topic 606, NGL pricing increased by 21 percent during 2018 as compared to 2017.

Crude oil revenues were approximately 92 percent of our total revenues during 2018 as compared to 88 percent during 2017. Total Eagle Ford revenues were approximately 99 percent of total revenues during 2018 and 96 percent in 2017. Effective August 2018, all of our revenues were derived from the Eagle Ford.

2017 vs. 2016. Our product revenues in 2017 increased over the combined Successor and Predecessor periods in 2016 due primarily to the significant increases in all product pricing which was partially offset by the decline in production described previously. Total crude oil revenues were approximately 88 percent during 2017 compared to 87 percent during the combined Successor and Predecessor periods in 2016. Total Eagle Ford revenues were approximately 96 percent of total revenues in 2017 compared to 95 percent in the combined Successor and Predecessor periods in 2016.

Effects of Derivatives

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

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Crude oil revenues as reported	$ 402,485	$ 140,886	$ 33,157	$ 81,377
Derivative settlements, net	(48,291)	(3,511)	384	48,008
	$ 354,194	$ 137,375	$ 33,541	$ 129,385
Crude oil prices per Bbl, as reported	$ 66.23	$ 50.96	$ 46.68	$ 35.21
Derivative settlements per Bbl	(7.95)	(1.27)	0.54	20.77
	$ 58.28	$ 49.69	$ 47.22	$ 55.98

Gain (Loss) on Sales of Assets

We recognize gains and losses on the sale or disposition of assets other than our oil and gas properties upon the completion of the underlying transactions.

The following table sets forth the total gains and losses recognized for the periods presented:

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Gain (loss) on sales of assets, net	$ (177)	$ (36)	$ (49)	$ 1,261

2018, 2017 and Successor Period in 2016. In 2018, 2017 and the Successor period in 2016, we recognized insignificant net losses attributable to sale of certain support equipment and tubular inventory and well materials.

Predecessor Period in 2016. The Predecessor period in 2016 includes $1.7 million from the amortization of deferred gains attributable to our 2014 sale of rights to construct a crude oil gathering and intermediate transportation system. The amortization of $0.3 million of deferred gains from the 2014 sale of our South Texas natural gas gathering and gas lift assets is also included for the Predecessor period in 2016. As of the Emergence Date, the unamortized portions of those deferred gains were reversed from our Consolidated Balance Sheet in connection with our application of Fresh Start Accounting and included as a component of Reorganization items, net.

Other Revenues, Net

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

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

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Other revenues, net	$ 1,479	$ 621	$ 398	$ (600)

2018 vs. 2017. Other revenues, net increased during 2018 from 2017 due primarily to higher fees charged to third parties resulting from substantially higher production.

2017 vs. 2016. Other revenues, net increased during 2017 from the combined Successor and Predecessor periods in 2016 due primarily to higher marketing fees partially offset by lower water disposal fees resulting from lower overall production. The combined Successor and Predecessor periods in 2016 included charges for reserves of certain of our receivables from joint venture partners and charges attributable to the accretion of unused firm transportation, both of which are presented as contra-revenue items in this caption. There were no firm transportation charges in 2017 because the underlying obligation was rejected in our bankruptcy proceedings.

Lease Operating Expenses

LOE include 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.

The following table sets forth our LOE for the periods presented:

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Lease operating	$ 35,879	$ 21,784	$ 5,331	$ 15,626
Per unit of production ($/BOE)	$ 4.52	$ 5.76	$ 5.13	$ 4.67

2018 vs. 2017. LOE increased on an absolute basis, but declined on a per unit basis during 2018 when compared to 2017. The absolute increases were due primarily to higher production volume including the incremental effects of the Devon and Hunt Acquisitions. The higher production volume also had the effect of decreasing the overall per unit cost, particularly those costs that have a higher fixed cost component. Furthermore, comprehensive maintenance costs in the second half of 2017 improved production and cost efficiency progressing throughout 2018.

2017 vs. 2016. LOE increased on an absolute and per unit basis during 2017 when compared to the combined Successor and Predecessor periods in 2016 due primarily to lower production volume, as well as higher surface and other repair and maintenance costs. We proceeded with certain of these repair and maintenance efforts during the third quarter of 2017 in order to recover a portion of the production shortfall brought about by Hurricane Harvey and the operational delays discussed above. While we incurred approximately $1 million of higher surface repair costs in 2017, they were partially offset by continuing cost containment efforts that we implemented throughout 2016 and into 2017 as well as the effects of lower industry-wide pricing for certain oilfield products and services.

Gathering Processing and Transportation

GPT includes costs that we incur to gather and aggregate our crude oil, NGL and natural gas production from our wells and deliver them via pipeline or truck to a central delivery point, downstream pipelines or processing plants, and blend or process, as necessary, depending upon the type of production and the specific contractual arrangements that we have with the applicable midstream operators.

The following table sets forth our GPT for the periods presented:

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Gathering, processing and transportation	$ 18,626	$ 10,734	$ 3,043	$ 13,235
Per unit of production ($/BOE)	$ 2.34	$ 2.84	$ 2.93	$ 3.96

2018 vs. 2017. GPT expense increased on an absolute basis during 2018 when compared to 2017 due primarily to substantially higher production volumes partially offset by the effect of the adoption of ASC Topic 606, or $2.4 million. Per unit costs declined $0.30 per BOE in 2018 due primarily to the effect of the adoption of ASC Topic 606, as well as a result of increased production sold at the wellhead with no corresponding GPT expense.

2017 vs. 2016. GPT decreased on an absolute and per unit basis during 2017 when compared to the combined Successor and Predecessor periods in 2016 due primarily to lower production volumes and decreased gathering rates pursuant to an amendment to our gathering agreement with Republic Midstream, which became effective in August of 2016. Prior to that time we had incurred $0.4 million of deficiency charges for production failing to meet our minimum volume commitments which were previously higher. We also incurred costs of approximately $0.5 million in the Predecessor periods in 2016 for unused firm transportation services in the Marcellus Shale prior to our termination of operations in that region. There were no such costs incurred in 2017 as the underlying contracts were rejected in our bankruptcy proceedings.

Production and Ad Valorem Taxes

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

The following table sets forth our production and ad valorem taxes for the periods presented:

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Production and ad valorem taxes				
Production/severance taxes	$ 20,619	$ 7,533	$ 1,801	$ 2,695
Ad valorem taxes	2,928	1,281	697	795
	$ 23,547	$ 8,814	$ 2,498	$ 3,490
Per unit of production ($/BOE)	$ 2.96	$ 2.33	$ 2.40	$ 1.04
Production/severance tax rate as a percent of product revenues	4.7%	4.7%	4.7%	2.9%

2018 vs. 2017. Production taxes increased on both an absolute and per unit basis during 2018 when compared to 2017 due primarily to increased production volume and higher commodity prices. Accruals for ad valorem taxes have also increased for 2018 as we have grown our assessable property base and we anticipate higher assessments as a result of higher commodity prices and increased working interests.

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

General and Administrative

Our G&A expenses include employee compensation, benefits and other related costs for our corporate management and governance functions, rent and occupancy costs for our corporate facilities, insurance, and professional fees and consulting costs supporting various corporate-level functions, among others. In order to facilitate a meaningful discussion and analysis of our results of operations with respect to G&A, we have disaggregated certain costs into three components as presented in the table below. Primary G&A encompasses all G&A costs except share-based compensation and certain significant special charges that are generally attributable to material stand-alone transactions or corporate actions that are not otherwise in the normal course.

The following table sets forth the components of G&A expenses for the periods presented:

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Primary G&A	$ 17,236	$ 13,072	$ 5,065	$ 15,607
Shares-based compensation				
Liability-classified	—	—	—	(19)
Equity-classified	4,618	3,809	81	1,511
Significant special charges				
Acquisition, divestiture and strategic transaction costs	3,960	1,340	—	—
Strategic and financial advisory costs	—	—	—	18,036
Executive retirement costs	250	—	—	—
Restructuring expenses	—	(20)	(80)	3,821
Total general and administrative expenses	$ 26,064	$ 18,201	$ 5,066	$ 38,956
Per unit of production ($/BOE)	$ 3.28	$ 4.82	$ 4.88	$ 11.64
Per unit of production excluding all share-based compensation and other significant special charges identified above ($/BOE)	$ 2.17	$ 3.46	$ 4.87	$ 4.66

2018 vs. 2017. Our primary G&A expenses increased on an absolute and decreased on a per unit basis during 2018 compared to 2017. The absolute increase is due primarily to the effects of higher payroll, benefits and support costs attributable to a higher overall employee headcount as well as costs associated with the relocation of our corporate headquarters to a new office within Houston, Texas. Higher production volume had the effect of reducing G&A per unit of production for 2018.

Equity-classified share-based compensation charges during all of the Successor periods are attributable to the amortization of compensation cost associated with the grants of time-vested restricted stock units, or RSUs, and performance restricted stock units, or PRSUs. The grants of RSUs and PRSUs are described in greater detail in Note 17 to the Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data.” A substantial portion of the share-based compensation expense is attributable to the RSU and PRSU grants made in the normal course in January 2017 and an RSU grants in September and December of 2016 in connection with our reorganization. The remainder is attributable to grants of RSUs and PRSUs to certain employees upon their hiring or as a result of promotion subsequent to the first quarter of 2017. The year 2018 also includes a charge of $0.6 million attributable to the accelerated vesting of certain RSUs and PRSUs in connection with the retirement of our Executive Chairman in February 2018. All of our equity-classified share-based compensation represents non-cash expenses.

During 2018, we incurred consulting and other costs associated with our review of strategic alternatives, including the Merger. In addition to these costs, we incurred transaction costs associated with the Mid-Continent divestiture and the Hunt Acquisition, including legal, due diligence and other professional fees. We also paid certain costs attributable to the retirement of our former Executive Chairman in February 2018. In the Successor periods in 2017, we recorded adjustments to severance-related restructuring accruals that were originally established in connection with our reorganization in the Predecessor period in 2016.

2017 vs. 2016. Our primary G&A expenses decreased on an absolute and per unit basis during 2017 compared to the combined Successor and Predecessor periods in 2016. The decrease is due primarily to the effects of: (i) lower payroll and benefits attributable to a lower overall employee headcount, (ii) the capitalization of certain labor and benefits costs to oil and gas properties in accordance with the full cost method in 2017, (iii) the relocation of our headquarters from Radnor, Pennsylvania to Houston, Texas and related move to a smaller office location, (iv) reduced travel and entertainment and (v) lower corporate support costs consistent with our efforts throughout 2016 and 2017 to decrease 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 adjustments associated with the change in fair value of the then-outstanding PBRSU grants. Our common stock performance relative to a defined peer group was less favorable during the 2016 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 in the Predecessor period in 2016 includes a charge for the cancellation of all of the RSUs outstanding prior to our bankruptcy filing in May 2016, partially offset by forfeitures of the Predecessor's stock options.

During 2017, we incurred transaction costs associated with the Devon Acquisition and certain costs in advance of the Hunt Acquisitions, including advisory, legal, due diligence and other professional fees. 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 45 employees during the combined Successor and Predecessor periods in 2016 and incurred related termination and severance benefit costs during the Predecessor periods.

Exploration

While applying the successful efforts method of accounting to our oil and gas properties during the Predecessor period in 2016, we incurred costs which were charged to operations in accordance with the successful efforts method. In the Successor periods, we applied the full cost method whereby these costs are capitalized. See the discussion of our capital expenditures program included in "*Financial Condition - Cash Flows*" above and Note 8 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for a discussion of certain capitalized costs.

The following table sets forth the components of exploration expenses for the periods presented:

	Successor			Predecessor
			September 13 Through December 31,	January 1 Through September 12,
	Year Ended December 31,			
	2018	2017	2016	2016
Unproved leasehold amortization	$ —	$ —	$ —	$ 1,940
Drilling rig termination charges	—	—	—	1,705
Drilling carry commitment	—	—	—	1,964
Geological and geophysical costs (seismic)	—	—	—	33
Other, primarily write-off of uncompleted wells	—	—	—	4,646
	$ —	$ —	$ —	$ 10,288

On the Emergence Date we adopted the full cost method. Accordingly, there are no exploration expenses recorded for any of the Successor periods. With respect to the Predecessor period in 2016, we recorded: (i) leasehold amortization attributable to our undeveloped properties, (ii) early termination charges in connection with the release of drilling rigs in the Eagle Ford, (iii) a charge attributable to our failure to complete a drilling carry requirement attributable to certain acreage acquired in the Eagle Ford in 2014, (iv) certain costs for acquired seismic data, (v) a charge of $4.0 million for the write-off of certain uncompleted well costs prior to the aforementioned change in accounting method and (vi) a charge of $0.6 million for coiled tubing services that were not utilized by the contract expiration date.

Depreciation, Depletion and Amortization (DD&A)

As discussed with respect to exploration expenses above, our adoption of the full cost method in place of the successful efforts method of accounting for oil and gas properties also impacted the determination of our DD&A during the Successor periods as compared to the Predecessor period in 2016. For a more detailed discussion of the determination of our DD&A, see the discussion of "*Critical Accounting Estimates*" that follows as well as Note 3 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

The following table sets forth total and per unit costs for DD&A for the periods presented:

	Successor			Predecessor
			September 13 Through December 31,	January 1 Through September 12,
	Year Ended December 31,			
	2018	2017	2016	2016
DD&A expense	$ 127,961	$ 48,649	$ 11,652	$ 33,582
DD&A rate ($/BOE)	$ 16.11	$ 12.87	$ 11.21	$ 10.04

2018 vs. 2017. DD&A increased on an absolute and per unit basis during 2018 when compared to 2017. Higher production volume provided for an increase of approximately $53.6 million while $25.7 million was attributable to the higher DD&A rates in 2018. The higher DD&A rates in the 2018 periods were attributable to costs added to the full cost pool, including those from the Devon and Hunt Acquisitions, during a period of rising crude oil prices, as well as the sale of our Mid-Continent properties in July 2018, while the DD&A rate for 2017 period is based primarily on the fair value of our properties at the time of our emergence from bankruptcy in September 2016.

2017 vs. 2016. Lower production volumes net of the effects of higher depletion rates were the primary factors attributable to the increase in DD&A during 2017 when compared to the combined Successor and Predecessor period in 2016. The Successor periods include a higher proportion of capitalized costs relative to the underlying proved reserves, consistent with the full cost method, when compared to the Predecessor periods which utilized the successful efforts method.

Interest Expense

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

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Interest on borrowings and related fees	$ 32,164	6,995	$ 678	$ 36,012
Accretion of original issue discount	680	161	—	—
Amortization of debt issuance costs	2,736	1,961	226	22,189
Capitalized interest	(9,118)	(2,725)	(25)	(183)
	$ 26,462	$ 6,392	$ 879	$ 58,018

2018 vs. 2017. Interest expense increased during 2018 as compared to 2017 due primarily to higher outstanding balances under the Credit Facility, including amounts borrowed to fund our larger capital expenditure program in 2018 and the Hunt Acquisition, as well as interest attributable to the Second Lien Facility that was entered into in September 2017. Furthermore, the Credit Facility and the Second Lien Facility are variable-rate instruments and both have been subject to periodic increases in LIBOR rates on a consistent basis since 2017. The accretion of original issue discount is entirely attributable to the Second Lien Facility while the amortization of debt issuance costs includes amounts attributable to both the Credit Facility and Second Lien Facility. We capitalized a larger portion of interest during 2018 as we maintained a substantially larger balance of unproved property as compared to 2017 due primarily to the Devon Acquisition.

2017 vs. 2016. Interest expense for 2017 is attributable to the Credit and Second Lien Facilities whereas interest expense during the Successor period in 2016 is exclusively attributable to the Credit Facility. Interest expense during the Predecessor period in 2016 is attributable to pre-petition credit facility, or RBL, and our 7.25% Senior Notes due 2019, or the 2019 Senior Notes, and our 8.50% Senior Notes due 2020, or the 2020 Senior Notes, and together with the 2019 Senior Notes, the Senior Notes. Weighted-average amounts outstanding under the Credit Facility during 2017 were lower than the combined weighted-average amounts outstanding under the Credit Facility and RBL during the combined 2016 periods resulting in lower expense. This was partially offset by interest expense on borrowings as well as amortization and accretion of debt issue costs and OID, respectively, attributable to the Second Lien Facility. The 2016 Predecessor period also includes a $20.5 million accelerated write-off of issuance costs associated with the RBL and Senior Notes in advance of our bankruptcy filings.

Derivatives

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.

The following table summarizes the gains and (losses) attributable to our crude oil derivatives portfolio for the periods presented:

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Crude oil derivative gains (losses)	$ 37,427	$ (17,819)	$ (16,622)	$ (8,333)

2018 vs. 2017. The forward curve for commodity prices declined relative to our weighted-average hedged prices during 2018 resulting in a net gain for the year ended December 31, 2018 while the forward curve for such prices increased relative to our weighted-average hedged prices during 2017. We paid cash settlements of $48.3 million in 2018 as compared to cash settlements paid of $3.5 million in 2017.

2017 vs. 2016. We paid cash settlements of $3.5 million in 2017 as compared to the receipt of $48.4 million of cash settlements from crude oil derivatives during the combined Successor and Predecessor periods in 2016. During 2017, prices under our derivative contracts were lower than the actual WTI crude oil prices resulting in net payments while the opposite situation occurred in the combined Successor and Predecessor periods in 2016 resulting in net receipts of cash settlements as well as the early termination of certain pre-petition derivative contracts in the Predecessor periods in 2016 which accelerated the receipt of cash settlements.

Other, Net

Other, net includes interest income, non-service costs associated with our retiree benefit plans and miscellaneous items of income and expense that are not directly associated with our current operations, including certain recoveries and write-offs attributable to prior years and properties that have been divested.

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

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Other, net	$ 2,266	$ 58	$ 792	$ (3,173)

2018. In 2018, we received a recovery of $1.5 million from partners attributable to a prior-year acquisition and received recoveries of $0.3 million of joint interest receivable balances previously written-off in connection with the bankruptcy of a former partner. We also received severance tax refunds attributable to previously-divested properties in excess of recorded amounts, interest income earned on the escrow account attributable to the Devon Acquisition prior to the escrow account's liquidation in March 2018 as well as recording the reversal of a litigation reserve attributable to previously-divested properties. The combined benefit to income from these items was approximately $0.7 million. These amounts were partially offset by interest charges applicable to a settlement with a royalty owner and charges associated with our retiree benefit plans.

2017. In 2017, we recorded interest income attributable to the escrow account attributable to the Devon Acquisition that was partially offset by charges associated with our retiree benefit plans and certain costs attributable to assets that were sold in prior years.

2016. In the Successor period of 2016, we reversed $0.9 million representing a portion of a reserve recognized in the Predecessor period of 2016 attributable to a prior-year acquisition-related receivable. This item was partially offset by the write-off of certain acquisition-related joint interest billing receivables and a decline in the market value of certain supplemental retirement plan assets prior to their reversion to us in connection with our emergence from bankruptcy. In the Predecessor period of 2016, we initially reserved the aforementioned acquisition-related receivable for $2.9 million and wrote-off unrecoverable amounts from prior years, including severance tax receivables, certain joint interest billing receivables, GPT and other revenue deductions due from other parties of $0.6 million, all of which were attributable primarily to properties that were sold in prior years. These items were partially offset by a vendor settlement of $0.3 million also attributable to prior periods.

Reorganization Items, Net

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

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Gains on the settlement of liabilities subject to compromise	$ —	$ —	$ —	$ 1,150,248
Fresh Start Accounting adjustments	—	—	—	28,319
Legal and professional fees and expenses	200	—	—	(29,976)
Settlements attributable to contract amendments	—	—	—	(2,550)
Debtor-in-Possession Facility costs and commitment fees	—	—	—	(170)
Write-off of prepaid directors and officers insurance	—	—	—	(832)
Other reorganization items	3,122	—	—	(46)
	$ 3,322	$ —	$ —	$ 1,144,993

2018. While we emerged from bankruptcy in September 2016, certain administrative and claims resolution activities continued until November 2018 when the Bankruptcy Court issued a final decree which effectively closed the case. Upon the closure, we reversed the remaining $0.2 million unused portion of an accrual that was established on the Emergence Date for legal and professional fees and administrative costs. In addition, we reversed the $2.7 million unallocated portion of a reserve that was established on the Emergence Date for the potential settlement of certain claims in cash. Finally, we also reversed $0.4 million of accounts payable that were held open since the Emergence Date as secured claims, but were ultimately expunged. As these items of income are directly attributable to the final administration of our bankruptcy case and not a part of our continuing operations, they are classified on our Consolidated Statement of Operations as components of "Reorganization items, net."

2016. The gains on the settlement of liabilities subject to compromise are primarily attributable to the Senior Notes and interest thereon. The Fresh Start Accounting adjustments include those fair value adjustments attributable to our property and equipment, asset retirement obligations, or AROs, retiree benefit obligations and the accelerated recognition of previously deferred gains of the Predecessor. The legal and professional fees that we incurred were attributable to our advisers as well as those of the various creditor committees, the RBL lenders and the indenture trustee under the Senior Notes. We paid settlements in cash with respect to certain critical contract amendments. While we did not borrow any amounts under the Debtor-in-Possession, or DIP, credit facility from the Petition Date through the Emergence Date, we paid certain costs and fees to arrange and maintain the DIP credit facility during this term. Upon emergence from bankruptcy, we wrote off certain prepaid directors and officers insurance attributable to the Predecessor.

The items described herein are also described in further detail in Note 4 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Income Taxes

The following table summarizes our income tax provision for the periods presented:

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Income tax (expense) benefit	$ (523)	$ 4,943	$ —	$ —
Effective tax rate	0.2%	17.8%	—%	—%

2018. The provision for the year ended December 31, 2018 includes a current federal benefit of $2.5 million attributable to the anticipated refund of alternative minimum tax, or AMT, credits for the 2018 tax year. This amount has been recognized as a current income tax receivable on our Consolidated Balance Sheet as of December 31, 2018. This benefit is offset by a corresponding decrease in the deferred tax asset associated with the refundable AMT credit giving rise to a deferred federal expense. In addition, we have a recognized a deferred state tax expense of $0.5 million for an overall effective tax rate of 0.2%.

2017. In connection with our analysis of the impact of the TCJA we recorded an income tax charge of $86.6 million for the year ended December 31, 2017, which consists of a reduction of deferred tax assets previously valued at 35%. We recorded a corresponding decrease in our deferred tax asset valuation allowance representing an income tax benefit for the same amount. In addition to the aforementioned offsetting items with respect to the reduction in income tax rates, our income tax provision included federal income taxes of $9.7 million applied at the statutory rate of 35% for 2017 and an adjustment of $10.8 million attributable to reductions in certain tax attributes of property and other adjustments of $0.3 million applied in connection with the filing of our 2016 income tax returns. These expenses were effectively offset by benefits attributable to the reduction in our deferred tax asset valuation allowance of $24.3 million and state income tax benefits of $1.4 million resulting in a net tax deferred benefit of $4.9 million, all of which is attributable to refundable AMT credit carryforwards.

2016. We recognized a federal income tax benefit for each of the Successor and Predecessor periods in 2016 at the statutory rate of 35%; however, the federal tax benefit 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.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2018, the material off-balance sheet arrangements and transactions that we have entered into included operating lease arrangements, information technology licensing, service agreements, employment agreements and letters of credit, all of which are customary in our business. Note that, effective January 1, 2019, the aforementioned lease arrangements will be recorded on our Consolidated Balance Sheet as described in greater detail in "*Disclosure of the Impact of Recently Issued Accounting Standards to be Adopted in the Future*" below and Note 2 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." See "*Contractual Obligations*" summarized below and Note 15 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for more details related to the value of our off-balance sheet arrangements. We did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise had we engaged in such relationships.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2018:

	Payments Due by Period				
	Total	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Credit Facility [1]	$ 321,000	$ —	$ 321,000	$ —	$ —
Second Lien Facility [2]	200,000	—	—	200,000	—
Interest payments on long-term debt [3]	103,821	38,187	51,483	14,151	—
Operating leases [4]	3,257	532	1,294	1,272	159
Crude oil gathering and transportation commitments [5]	114,300	11,702	25,924	25,924	50,750
Drilling and completion commitments [6]	20,692	20,692	—	—	—
Asset retirement obligations [7]	114,553	—	—	—	114,553
Derivatives	991	991	—	—	—
Other commitments [8]	419	254	165	—	—
Total contractual obligations	$ 879,033	$ 72,358	$ 399,866	$ 241,347	$ 165,462

[1] Assumes that the amount outstanding of $321 million as of December 31, 2018 will remain outstanding until its maturity in 2020. The Credit Facility has been classified as a long term liability on our Consolidated Balance Sheet as described in "Financial Condition – Liquidity" and in Note 10 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[2] Assumes that the amount outstanding of $200 million as of December 31, 2018 will remain outstanding until its maturity in 2022. The Second Lien Facility has been classified as a long term liability on our Consolidated Balance Sheet as described in "Financial Condition – Liquidity" and in Note 10 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[3] Represents estimated interest payments that will be due under the Credit Facility and Second Lien Facility, assuming that the underlying LIBOR-based interest rates in effect at December 31, 2018 remain in effect and the amounts outstanding of $321 million and $200 million as of December 31, 2018, respectively, will remain outstanding until their maturities in 2020 and 2022, respectively.

[4] Relates primarily to office facilities and equipment leases.

[5] Represents minimum payments for gathering and intermediate pipeline transportation services for our crude oil and condensate production in South Texas. The gathering portion of these commitments is recognized as GPT while the intermediate transportation and pipeline support components are recognized as a reduction to the index-based price that we receive from crude oil sold to Republic Midstream.

[6] Includes fixed-term commitments for one drilling rig and one frac service crew and materials. Does not include commitments for drilling rigs contracted on a pad-to-pad basis

[7] Represents the undiscounted balance payable, primarily for the plugging of inactive wells, in periods more than five years in the future for which $4.3 million, on a discounted basis, has been recognized on our Consolidated Balance Sheet as of December 31, 2018. While we may make payments to settle certain AROs, including those subject to regulatory requirements during each of the next five years, no material amounts are currently required by contract or regulatory authority to be made during this time frame.

[8] Represents all other significant obligations including information technology licensing and service agreements, among others.

Critical Accounting Estimates

The process of preparing financial statements in accordance with 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. We consider the following to be the most critical accounting estimates requiring judgment of our management.

Fresh Start Accounting

On the Emergence Date, we adopted Fresh Start Accounting. Fresh Start Accounting involved a comprehensive valuation process in which we determined the fair value of all of our assets and liabilities on the Emergence Date. This process, which is more fully described in Note 4 to our Consolidated Financial Statements included in Item II, Part 8, "Financial Statements and Supplementary Data," utilized several critical estimates associated with, among other items, our development plans, financial projections, regional and broader market conditions as well as an estimated discount rate.

Oil and Gas Reserves

Estimates of our oil and gas reserves are the most critical estimate included in our Consolidated Financial Statements. Reserve estimates become the basis for determining depletive write-off rates and the recoverability of historical cost investments. There are many uncertainties inherent in estimating crude oil, NGL and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the amount and timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

There are several factors which could change the estimates of our oil and gas reserves. Significant rises or declines in commodity product prices as well as changes in our drilling plans could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs.

Oil and Gas Properties

Beginning on the Emergence Date, we have applied the full cost method to account for our oil and gas properties. Under this method, all productive and nonproductive costs incurred in the exploration, development and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical, or seismic, drilling, completion and equipment costs. Internal costs incurred that are directly attributable to exploration, development and acquisition activities undertaken by us for our own account, and which are not attributable to production, general corporate overhead or similar activities are also capitalized. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized as a component of DD&A.

Unproved properties not being amortized include unevaluated leasehold costs and associated capitalized interest. These costs are reviewed quarterly to determine whether or not and to what extent proved reserves have been assigned to a property or if an impairment has occurred due to lease expirations, general economic conditions and other factors, in which case, the related costs along with associated capitalized interest are reclassified to the proved oil and gas properties subject to DD&A. Factors we consider in our assessment include drilling results, the terms of oil and gas leases not held by production and drilling and completion capital expenditures consistent with our plans.

At the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes, or a Ceiling Test. The estimated discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development. As of December 31, 2018, the carrying value of our proved oil and gas properties was below the limit determined by the Ceiling Test by approximately $800 million.

Depreciation, Depletion and Amortization

DD&A of our oil and gas properties is computed using the units-of-production method. We apply this method by multiplying the unamortized cost of our proved oil and gas properties, net of estimated salvage plus future development costs, by a rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period.

Derivative Activities

From time to time, we enter into derivative instruments to mitigate our exposure to commodity price volatility. The derivative financial instruments that we employ, which are placed with financial institutions that we believe are of acceptable credit risk, generally take the form of collars and swaps, among others. All derivative instruments are recognized in our Consolidated Financial Statements at fair value with the changes recorded currently in earnings. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

Deferred Tax Asset Valuation Allowance

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized after consideration of future taxable income and reasonable tax planning strategies. In the event that we were to determine that we would not be able to realize all or a part of our deferred tax assets for which a valuation allowance had not been established, an adjustment to the deferred tax asset will be reflected in income in the period such determination is made. The most significant matter applicable to the realization of our deferred tax assets is attributable to net operating losses at the federal level as well as certain states in which we operate. Estimates of future taxable income inherently reflect a significant degree of uncertainty. As of December 31, 2018, we had a full valuation allowance for all of our net deferred tax assets, with the exception of our remaining refundable AMT credit carryforwards, due primarily to our inability to project sufficient future taxable income in both the federal and various state jurisdictions.

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

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 reasonably 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 which have a higher credit risk than those associated with our traditional customer receivables. 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 continuing to evaluate the requirements and the period for which we will adopt the standard as well as monitoring developments regarding ASU 2016–13 that are unique to our industry.

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. Together with recent related amendments to GAAP, ASU 2016–02 represents ASC Topic 842 *Leases*, or ASC Topic 842, which supersedes all current GAAP with respect to leases. 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. ASC Topic 842 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASC Topic 842 is January 1, 2019, with early adoption permitted.

ASC Topic 842 will be applicable to our existing leases for office facilities and certain office equipment, certain field equipment, land easements and similar arrangements for rights-of-way, certain natural gas gathering and gas lift assets and potentially to certain drilling rig contracts with terms in excess of 12 months to the extent we may have such contracts in the future. We are finalizing our evaluation of the impact that the adoption may have on certain crude oil gathering arrangements.

We will adopt ASC Topic 842 effective January 1, 2019 using the modified retrospective method with a cumulative effect charge to the beginning balance of retained earnings that is not anticipated to be material. We anticipate recognizing total right-of-use assets and lease of obligations of approximately $3 million, excluding any potential impact attributable to our crude oil gathering arrangements. Upon adoption, all of the leases for which we are recognizing assets and liabilities will be classified as operating leases. We also have identified certain contractual arrangements that will be classified as variable leases. We plan to adopt certain practical expedients provided for in ASC Topic 842 including (i) those associated with the reassessment and classification of existing leases, (ii) land easements and (iii) an election to not separate lease and non-lease components. We also plan to make an accounting policy election, effective January 1, 2019, whereby any leases with terms of one year or less will be formally classified as short-term leases.

Item 7A Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and commodity price risk.

Interest Rate Risk

Our interest rate risk is attributable to our borrowings under the Credit Facility and the Second Lien Facility, which are subject to variable interest rates. As of December 31, 2018, we had borrowings of $321 million under the Credit Facility at an interest rate of 5.96%. As of December 31, 2018, we had borrowings of $190.4 million under the Second Lien Facility, net of OID and issuance costs, at an interest rate of 9.53%. Assuming a constant borrowing level under the Credit and Second Lien Facilities, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in interest expense of approximately $5.2 million on an annual basis.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars and swaps) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of oil and natural gas. We are not currently utilizing any derivative instruments with respect to NGLs and natural gas, although we may do so in the future.

As of December 31, 2018, we reported a net commodity derivative asset of $44.0 million. The contracts associated with this position are with eight 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.

During the year ended December 31, 2018, we reported net commodity derivative gains of $37.4 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 7 to our Consolidated Financial Statements included in Part II, Item 8, included in Part II, Item 8, “Financial Statements and Supplementary Data” for a further description of our price risk management activities.

The following table sets forth our commodity derivative positions as of December 31, 2018:

	Instrument	Average Volume Per Day	Weighted Average Price	Fair Value: Asset	Fair Value: Liability
Crude Oil:		(barrels)	($/barrel)		
First quarter 2019	Swaps-WTI	6,446	$ 54.46	$ 4,959	$ —
First quarter 2019	Swaps-LLS	5,000	$ 59.17	3,684	—
Second quarter 2019	Swaps-WTI	6,421	$ 54.48	4,307	—
Second quarter 2019	Swaps-LLS	5,000	$ 59.17	3,203	—
Third quarter 2019	Swaps-WTI	6,397	$ 54.50	3,821	—
Third quarter 2019	Swaps-LLS	5,000	$ 59.17	3,092	—
Fourth quarter 2019	Swaps-WTI	6,398	$ 54.50	3,498	—
Fourth quarter 2019	Swaps-LLS	5,000	$ 59.17	3,015	—
First quarter 2020	Swaps-WTI	6,000	$ 54.09	2,807	—
Second quarter 2020	Swaps-WTI	6,000	$ 54.09	2,609	—
Third quarter 2020	Swaps-WTI	6,000	$ 54.09	2,450	—
Fourth quarter 2020	Swaps-WTI	6,000	$ 54.09	2,234	—

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying commodity prices. This illustration assumes that crude oil volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling outstanding derivative positions.

	Change of $10.00 per Barrel of Crude Oil ($ in millions)	
	Increase	**Decrease**
Effect on the fair value of crude oil derivatives	$ (62.1)	$ 62.1
Effect on 2019 operating income, excluding crude oil derivatives [1]	$ 55.0	$ (55.0)

[1] Based on our 2019 Business Plan consistent with the assumptions used to determine our proved reserves as disclosed in Item 2, "Properties – *Summary of Oil and Gas Reserves*."

Item 8 Financial Statements and Supplementary Data

PENN VIRGINIA CORPORATION
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Penn Virginia Corporation

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation (a Virginia corporation) and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the two years in the period ended December 31, 2018 (Successor) and for the period from September 13, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through September 12, 2016 (Predecessor), and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 (Successor) and the period from September 13, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through September 12, 2016 (Predecessor), in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 27, 2019 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2016.

Houston, Texas
February 27, 2019

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Penn Virginia Corporation

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Penn Virginia Corporation (a Virginia corporation) and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2018, and our report dated February 27, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Houston, Texas
February 27, 2019

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

	Successor			Predecessor
			September 13, Through	January 1, Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Revenues				
Crude oil	$ 402,485	$ 140,886	$ 33,157	$ 81,377
Natural gas liquids	21,073	10,066	2,707	6,064
Natural gas	15,972	8,517	2,790	6,208
Gain (loss) on sales of assets, net	(177)	(36)	(49)	1,261
Other revenues, net	1,479	621	398	(600)
Total revenues	440,832	160,054	39,003	94,310
Operating expenses				
Lease operating	35,879	21,784	5,331	15,626
Gathering, processing and transportation	18,626	10,734	3,043	13,235
Production and ad valorem taxes	23,547	8,814	2,498	3,490
General and administrative	26,064	18,201	5,066	38,956
Exploration	—	—	—	10,288
Depreciation, depletion and amortization	127,961	48,649	11,652	33,582
Total operating expenses	232,077	108,182	27,590	115,177
Operating income (loss)	208,755	51,872	11,413	(20,867)
Other income (expense)				
Interest expense, net of amounts capitalized	(26,462)	(6,392)	(879)	(58,018)
Derivatives	37,427	(17,819)	(16,622)	(8,333)
Other, net	2,266	58	792	(3,173)
Reorganization items, net	3,322	—	—	1,144,993
Income (loss) before income taxes	225,308	27,719	(5,296)	1,054,602
Income tax (expense) benefit	(523)	4,943	—	—
Net income (loss)	224,785	32,662	(5,296)	1,054,602
Preferred stock dividends	—	—	—	(5,972)
Net income (loss) attributable to common shareholders	$ 224,785	$ 32,662	$ (5,296)	$ 1,048,630
Net income (loss) per share:				
Basic	$ 14.93	$ 2.18	$ (0.35)	$ 11.91
Diluted	$ 14.70	$ 2.17	$ (0.35)	$ 8.50
Weighted average shares outstanding – basic	15,059	14,996	14,992	88,013
Weighted average shares outstanding – diluted	15,292	15,063	14,992	124,087

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Net income (loss)	$ 224,785	$ 32,662	$ (5,296)	$ 1,054,602
Other comprehensive income (loss):				
Change in pension and postretirement obligations, net of tax of $0 for 2018 and 2017, $39 for the Successor period from September 13, 2016 through December 31, 2016 and $(226) for the Predecessor period from January 1, 2016 through September 12, 2016.	82	(73)	73	(421)
	82	(73)	73	(421)
Comprehensive income (loss)	$ 224,867	$ 32,589	$ (5,223)	$ 1,054,181

See accompanying notes to consolidated financial statements.

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

	December 31,			
		2018		2017
Assets				
Current assets				
Cash and cash equivalents	$	17,864	$	11,017
Accounts receivable, net of allowance for doubtful accounts		66,038		69,821
Derivative assets		34,932		—
Income taxes receivable		2,471		—
Other current assets		5,125		6,250
Total current assets		126,430		87,088
Property and equipment, net		927,994		529,059
Derivative assets		10,100		—
Deferred income taxes		1,949		4,943
Other assets		2,481		8,507
Total assets	$	1,068,954	$	629,597
Liabilities and Shareholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	$	103,700	$	96,181
Derivative liabilities		991		27,777
Total current liabilities		104,691		123,958
Other liabilities		5,533		4,833
Derivative liabilities		—		13,900
Long-term debt		511,375		265,267
Commitments and contingencies (Note 15)				
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; 15,080,594 and 15,018,870 shares issued as of December 31, 2018 and December 31, 2017, respectively		151		150
Paid-in capital		197,630		194,123
Retained earnings		249,492		27,366
Accumulated other comprehensive income		82		—
Total shareholders' equity		447,355		221,639
Total liabilities and shareholders' equity	$	1,068,954	$	629,597

See accompanying notes to consolidated financial statements.

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

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		December 31,	September 12,
	2018	2017	2016	2016
Cash flows from operating activities				
Net income (loss)	$ 224,785	$ 32,662	$ (5,296)	$ 1,054,602
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash reorganization items	(3,322)	—	—	(1,178,302)
Depreciation, depletion and amortization	127,961	48,649	11,652	33,582
Accretion of firm transportation obligation	—	—	—	317
Derivative contracts:				
Net (gains) losses	(37,427)	17,819	16,622	8,333
Cash settlements, net	(48,291)	(3,511)	384	48,008
Deferred income tax expense (benefit)	2,994	(4,943)	—	—
Loss (gain) on sales of assets, net	177	36	49	(1,261)
Non-cash exploration expense	—	—	—	6,038
Non-cash interest expense	3,416	2,122	226	22,189
Share-based compensation (equity-classified)	4,618	3,809	81	1,511
Other, net	44	61	21	(13)
Changes in operating assets and liabilities:				
Accounts receivable, net	(23,674)	(43,318)	10,791	12,273
Accounts payable and accrued expenses	21,109	28,542	(3,887)	22,469
Other assets and liabilities	(258)	(218)	131	501
Net cash provided by operating activities	272,132	81,710	30,774	30,247
Cash flows from investing activities				
Acquisitions, net	(85,387)	(200,849)	—	—
Capital expenditures	(430,592)	(115,687)	(4,812)	(15,359)
Proceeds from sales of assets, net	7,683	869	—	224
Other, net	—	—	(104)	1,186
Net cash used in investing activities	(508,296)	(315,667)	(4,916)	(13,949)
Cash flows from financing activities				
Proceeds from credit facility borrowings	244,000	59,000	—	75,350
Repayment of credit facility borrowings	—	(7,000)	(50,350)	(119,121)
Proceeds from second line note	—	196,000	—	—
Debt issuance costs paid	(989)	(9,787)	—	(3,011)
Proceeds received from rights offering, net	—	55	—	49,943
Other, net	—	(55)	(161)	—
Net cash provided by (used in) financing activities	243,011	238,213	(50,511)	3,161
Net increase (decrease) in cash and cash equivalents	6,847	4,256	(24,653)	19,459
Cash and cash equivalents - beginning of period	11,017	6,761	31,414	11,955
Cash and cash equivalents - end of period	$ 17,864	$ 11,017	$ 6,761	$ 31,414
Supplemental disclosures:				
Cash paid for interest (net of amounts capitalized)	$ 22,599	$ 4,102	$ 598	$ 4,331
Cash paid for income taxes (net of refunds)	$ —	$ —	$ (7)	$ (35)
Cash paid for reorganization items, net	$ 540	$ 954	$ 525	$ 30,990
Non-cash investing and financing activities:				
Common stock issued in exchange for liabilities	$ —	$ —	$ —	$ 140,952
Changes in accrued liabilities related to capital expenditures	$ 44	$ 19,910	$ 997	$ (11,301)
Derivatives settled to reduce outstanding debt	$ —	$ —	$ —	$ 51,979

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Shares Outstanding	Preferred Stock	Common Stock	Paid-in Capital	Retained Earnings (Accumulated Deficit)	Deferred Compensation Obligation	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders' Equity (Deficit)
Balance as of December 31, 2015 (Predecessor)	81,253	3,146	628	1,211,088	(2,130,271)	3,440	422	(3,574)	(915,121)
Net income	—	—	—	—	1,054,602	—	—	—	1,054,602
Share-based compensation	—	—	—	1,511	—	—	—	—	1,511
All other changes	6,965	(1,266)	69	1,198	—	—	(39)	—	(38)
Balance, September 12, 2016 (Predecessor)	88,218	1,880	697	1,213,797	(1,075,669)	3,440	383	(3,574)	140,954
Cancellation of Predecessor equity	(88,218)	(1,880)	(697)	(1,213,797)	1,075,669	(3,440)	(383)	3,574	(140,954)
Balance, September 12, 2016 (Predecessor)	—	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Issuance of Successor common stock - Rights Offering	7,634	$ —	$ 76	$ 49,867	$ —	$ —	$ —	$ —	$ 49,943
Issuance of Successor common stock - Backstop Fee	473	—	5	9,054	—	—	—	—	9,059
Issuance of Successor common stock - exchange of claims	6,885	—	69	131,824	—	—	—	—	131,893
Balance, September 12, 2016 (Successor)	14,992	—	150	190,745	—	—	—	—	190,895
Net loss	—	—	—	—	(5,296)	—	—	—	(5,296)
Share-based compensation	—	—	—	81	—	—	—	—	81
All other changes	—	—	—	(205)	—	—	73	—	(132)
Balance as of December 31, 2016	14,992	—	150	190,621	(5,296)	—	73	—	185,548
Net income	—	—	—	—	32,662	—	—	—	32,662
Share-based compensation	—	—	—	3,809	—	—	—	—	3,809
Restricted stock unit vesting	27	—	—	(351)	—	—	—	—	(351)
All other changes	—	—	—	44	—	—	(73)	—	(29)
Balance as of December 31, 2017	15,019	—	150	194,123	27,366	—	—	—	221,639
Net income	—	—	—	—	224,785	—	—	—	224,785
Share-based compensation	—	—	—	4,618	—	—	—	—	4,618
Restricted stock unit vesting	61	—	1	(1,111)	—	—	—	—	(1,110)
Cumulative effect of change in accounting principle (see Note 6)	—	—	—	—	(2,659)	—	—	—	(2,659)
All other changes	—	—	—	—	—	—	82	—	82
Balance as of December 31, 2018	15,080	$ —	$ 151	$ 197,630	$ 249,492	$ —	$ 82	$ —	$ 447,355

See accompanying notes to consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation (together with its consolidated subsidiaries unless the context otherwise requires, "Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company engaged in the onshore exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

On October 28, 2018, Denbury Resources Inc. ("Denbury") and Penn Virginia announced that they entered into a definitive merger agreement (the "Merger Agreement") pursuant to which Denbury will acquire Penn Virginia (the "Merger"). The consideration to be paid to Penn Virginia shareholders will consist of 12.4 shares of Denbury common stock and $25.86 of cash for each share of Penn Virginia common stock. Penn Virginia shareholders will be permitted to elect to receive either all cash, all stock or a mix of stock and cash, in each case subject to proration, which will result in the aggregate issuance by Denbury of approximately 191.667 million Denbury shares and payment by Denbury of $400 million in cash. The transaction was unanimously approved by the board of directors of each company, and certain Penn Virginia shareholders holding approximately 15 percent of the outstanding shares signed voting agreements to vote "for" the transaction. The transaction is subject to the approval by the holders of more than two-thirds of the outstanding Company common shares, the approval by the holders of a majority of the outstanding Denbury common shares of an amendment to the certificate of incorporation to increase the number of authorized Denbury common shares, the approval of the issuance of Denbury common shares in the Merger by the holders of a majority of the Denbury common shares represented in person or by proxy at a meeting of Denbury shareholders held to vote on such matter and other customary closing conditions. The special meeting of shareholders to approve the merger is anticipated in April 2019 and closing is anticipated soon thereafter, subject to shareholder approval and certain other conditions. The Merger Agreement contains certain termination rights for both Denbury and the Company, including if the Merger is not consummated by April 30, 2019, and requires Penn Virginia to pay a $45 million termination fee in certain circumstances.

2. Basis of Presentation

Comparability of Financial Statements to Prior Periods

As described in further detail in Note 4 below, we have adopted and applied the relevant guidance provided in accounting principles generally accepted in the United States of America ("GAAP") with respect to the accounting and financial statement disclosures for entities that have emerged from bankruptcy proceedings ("Fresh Start Accounting"). Accordingly, our Consolidated Financial Statements and Notes after September 12, 2016, are not comparable to the Consolidated Financial Statements and Notes through that date. To facilitate our financial statement presentations, we refer to the reorganized company in these Consolidated Financial Statements and Notes as the "Successor" for periods subsequent to September 12, 2016, and the "Predecessor" for periods prior to September 13, 2016. Furthermore, our Consolidated Financial Statements and Notes have been presented with a "black line" division to delineate the lack of comparability between the Predecessor and Successor. In addition, 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 and financial position for the Successor periods will be substantially different from our historic trends.

We have applied the relevant guidance provided in GAAP with respect to the accounting and financial statement disclosures for entities that have filed petitions with the bankruptcy court and expect to reorganize as going concerns in preparing our Consolidated Financial Statements and Notes through the period ended September 12, 2016, or Predecessor periods. That guidance requires that, for periods subsequent to our bankruptcy filing on May 12, 2016, or post-petition periods, certain transactions and events that were directly related to our reorganization be distinguished from our normal business operations. Accordingly, certain revenues, expenses, realized gains and losses and provisions that were realized or incurred in connection with the bankruptcy proceedings have been included in "Reorganization items, net" in our Consolidated Statement of Operations for the period ended September 12, 2016. In addition, certain liabilities and other obligations incurred prior to May 12, 2016, or pre-petition periods, have been classified in "Liabilities subject to compromise" on our Predecessor Consolidated Balance Sheet through September 12, 2016. Further detail for our "Reorganization items, net" and "Liabilities subject to compromise" are provided in Note 4 below.

Going Concern Presumption

Our 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 Consolidated Financial Statements and has concluded that no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes thereto.

Adoption of Recently Issued Accounting Pronouncements

Effective January 1, 2018, we adopted and began applying the relevant guidance provided in Accounting Standards Update ("ASU") 2017–07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* ("ASU 2017–07"). ASU 2017–07 requires employers to disaggregate the service cost component from the other components of net periodic 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 periodic 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 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 there are interest and other costs associated with the legacy obligations. As required, ASU 2017–07 has been applied retrospectively to periods prior to 2018. Accordingly, the entirety of the expense associated with these plans, which was less than $0.1 million, has been included as a component of the "Other income (expense)" caption in our Consolidated Statements of Operations for all periods presented. Prior to 2018, all costs associated with these plans were included in the "General and administrative" ("G&A") expenses caption.

Effective January 1, 2018, we adopted and began applying the relevant guidance provided in ASU 2014–09, *Revenues from Contracts with Customers* ("ASU 2014–09") and related amendments to GAAP which, together with ASU 2014–09, represent Accounting Standards Codification ("ASC") Topic 606, *Revenues from Contracts with Customers* ("ASC Topic 606"). We adopted ASC Topic 606 using the cumulative effect transition method (see Note 6 for the impact and disclosures associated with the adoption of ASC Topic 606).

Recently Issued Accounting Pronouncements Pending Adoption

In June 2016, the Financial Accounting Standards Board ("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 which have a higher credit risk than those associated with our traditional customer receivables. 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 continuing to evaluate the requirements and the period for which we will adopt the standard as well as monitoring developments regarding ASU 2016–13 that are unique to our industry.

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. Together with recent related amendments to GAAP, ASU 2016–02 represents ASC Topic 842, *Leases* ("ASC Topic 842") which supersedes all current GAAP with respect to leases. 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. ASC Topic 842 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASC Topic 842 is January 1, 2019, with early adoption permitted.

ASC Topic 842 will be applicable to our existing leases for office facilities and certain office equipment, certain field equipment, land easements and similar arrangements for rights-of-way, certain gas gathering and gas lift assets and potentially to certain drilling rig contracts with terms in excess of 12 months, to the extent we may have such contracts in the future. We are finalizing our evaluation of the impact that the adoption may have on certain crude oil gathering arrangements.

We will adopt ASC Topic 842 effective January 1, 2019 using the modified retrospective method with a cumulative effect charge to the beginning balance of retained earnings that is not anticipated to be material. We anticipate recognizing total right-of-use assets and lease of obligations of approximately $3 million, excluding any potential impact attributable to our crude oil gathering arrangements. All of the leases for which we are recognizing assets and liabilities will be classified as operating leases. We also have identified certain contractual arrangements that will be classified as variable leases. We plan to adopt certain practical expedients provided for in ASC Topic 842 including (i) those associated with the reassessment and classification of existing leases, (ii) land easements and (iii) an election to not separate lease and non-lease components. We also plan to make an accounting policy election, effective January 1, 2019, whereby any leases with terms of one year or less will be formally classified as short-term leases.

3. Summary of Significant Accounting Policies

Principles of Consolidation

Our Consolidated Financial Statements include the accounts of Penn Virginia and all of its subsidiaries. Intercompany balances and transactions have been eliminated.

Use of Estimates

Preparation of our Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in our Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Such estimates include certain asset and liability valuations as further described in these Notes. Actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Derivative Instruments

From time to time, we utilize derivative instruments to mitigate our financial exposure to commodity price and interest rate volatility. The derivative instruments, which are placed with financial institutions that we believe are of acceptable credit risk, generally take the form of collars and swaps. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

All derivative instruments are recognized in our Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. Our derivative instruments are not formally designated as hedges. We recognize changes in fair value in earnings currently as a component of the Derivatives caption in our Consolidated Statements of Operations. We have experienced and could continue to experience significant changes in the amount of derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts, which fluctuate with changes in commodity prices and interest rates.

Oil and Gas Properties

We apply the full cost method of accounting for our oil and gas properties which we adopted effective with our adoption of Fresh Start Accounting. Under this method, all productive and nonproductive costs incurred in the exploration, development and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical, or seismic, drilling, completion and equipment costs. Internal costs incurred that are directly attributable to exploration, development and acquisition activities undertaken by us for our own account, and which are not attributable to production, general corporate overhead or similar activities are also capitalized. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized as a component of depreciation, depletion and amortization (“DD&A”).

Unproved properties not being amortized include unevaluated leasehold costs and associated capitalized interest. These costs are reviewed quarterly to determine whether or not and to what extent proved reserves have been assigned to a property or if an impairment has occurred due to lease expirations, general economic conditions and other factors, in which case the related costs along with associated capitalized interest are reclassified to the proved oil and gas properties subject to DD&A.

At the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes (a “Ceiling Test”). The estimated discounted future net revenues are determined using the prior 12-month’s average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development.

For the periods prior to the Emergence Date, we applied the successful efforts method of accounting for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs were capitalized. Seismic costs, delay rentals and costs to drill exploratory wells that did not find proved reserves were expensed as oil and gas exploration. We carried the costs of exploratory wells as assets if the wells had found a sufficient quantity of reserves to justify its completion as a producing well and as long as we were making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may have taken us more than one year to evaluate the future potential of the exploratory well and make determinations of their economic viability. Our ability to move forward on projects was dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which was beyond our control. In such cases, exploratory well costs remained suspended as long as we were actively pursuing access to the necessary facilities or receiving such permits and approvals and believed that they would be obtained. We assessed the status of suspended exploratory well costs on a quarterly basis.

Depreciation, Depletion and Amortization

DD&A of our oil and gas properties is computed using the units-of-production method. We apply this method by multiplying the unamortized cost of our proved oil and gas properties, net of estimated salvage plus future development costs, by a rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period.

DD&A of our proved properties while we applied the successful efforts method during the Predecessor periods was computed using the units-of-production method. Historically, we adjusted our depletion rate throughout the year as new data became available.

Other Property and Equipment

Other property and equipment consists primarily of gathering systems and related support equipment. Property and equipment are carried at cost and include expenditures for additions and improvements which increase the productive lives of existing assets. Maintenance and repair costs are charged to expense as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized.

We compute depreciation and amortization of property and equipment using the straight-line balance method over the estimated useful life of each asset as follows: Gathering systems – fifteen to twenty years and Other property and equipment – three to twenty years.

Impairment of Long-Lived Assets

While we applied the successful efforts method of accounting for our oil and gas properties during the Predecessor periods, we reviewed our assets for impairment when events or circumstances indicated a possible decline in the recoverability of the carrying value of the properties. If the carrying value of the asset was determined to be impaired, we reduced the asset to its fair value. Fair value may have been estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows were based on management's expectations for the future and included estimates of future production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, intent to develop properties and a risk-adjusted discount rate.

We reviewed oil and gas properties for impairment periodically when events and circumstances indicated a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimated the future cash flows expected in connection with the properties and compared such future cash flows to the carrying amounts of the properties to determine if the carrying amounts were recoverable. Performing the impairment evaluations required use of judgments and estimates since the results were dependent on future events. Such events included estimates of proved and unproved reserves, future commodity prices, the timing of future production, capital expenditures and intent to develop properties, among others.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, were capitalized pending the results of exploration efforts. Unproved properties whose acquisition costs were insignificant to total oil and gas properties were amortized in the aggregate over the lesser of five years or the average remaining lease term and the amortization was charged to exploration expense. We assessed unproved properties whose acquisition costs were relatively significant, if any, for impairment on a stand-alone basis. As exploration work progressed and the reserves on properties were proved, capitalized costs of these properties became subject to depreciation and depletion. If the exploration work was unsuccessful, the capitalized costs of the properties related to the unsuccessful work was charged to exploration expense. The timing of any write-downs of any significant unproved properties depended upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. Associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our AROs relate to the plugging and abandonment of oil and gas wells and the associated asset is recorded as a component of oil and gas properties. After recording these amounts, the ARO is accreted to its future estimated value, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion of the ARO and the depreciation of the related long-lived assets are included in the DD&A expense caption in our Consolidated Statements of Operations.

Income Taxes

We recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Using this method, deferred tax assets and liabilities are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates. In assessing our deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is assessed at each reporting period and is dependent upon the generation of future taxable income and our ability to utilize tax credits and operating loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies. We recognize interest attributable to income taxes, to the extent they arise, as a component of interest expense and penalties as a component of income tax expense.

We are subject to ongoing tax examinations in numerous domestic jurisdictions. Accordingly, we may record incremental tax expense based upon the more-likely-than-not outcomes of uncertain tax positions. In addition, when applicable, we adjust the previously recorded tax expense to reflect examination results when the position is effectively settled. Our ongoing assessments of the more-likely-than-not outcomes of the examinations and related tax positions require judgment and can increase or decrease our effective tax rate, as well as impact our operating results. The specific timing of when the resolution of each tax position will be reached is uncertain.

Revenue Recognition and Associated Costs

Crude oil. We sell our crude oil production to our customers at either the wellhead or a contractually agreed-upon delivery point, including certain regional central delivery point terminals or pipeline inter-connections. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality, location differentials and, if applicable, deductions for intermediate transportation. Costs incurred by us for gathering and transporting the products to an agreed-upon delivery point are recognized as a component of GPT expense.

NGLs. We have natural gas processing contracts in place with certain midstream processing vendors. We deliver "wet" natural gas to our midstream processing vendors at the inlet of their processing facilities through gathering lines, certain of which we own and others which are owned by gathering service providers. Subsequent to processing, NGLs are delivered or otherwise transported to a third-party customer. Depending upon the nature of the contractual arrangements with the midstream processing vendors, particularly those attributable to the marketing of the NGL products, we recognize revenue for NGL products on either a gross or net basis. For those contracts where we have determined that we are the principal, and the ultimate third party is our customer, we recognize revenue on a gross basis, with associated processing costs presented as GPT expenses. For those contracts where we have determined that we are the agent and the midstream processing vendor is our customer, we recognize NGL product revenues based on a net basis with processing costs presented as a reduction of revenue. Based on an analysis of all of our existing natural gas processing contracts, we have determined that, as of January 1, 2018, and through December 31, 2018, we were the agent and our midstream processing vendors were our customers with respect to all of our NGL product sales.

Natural gas. Subsequent to the aforementioned processing of "wet" natural gas and the separation of NGL products, the "dry" or residue gas is delivered to us at the tailgate of the midstream processing vendors' facilities and we market the product to our customers, most of whom are interstate pipelines. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality and location differentials, as applicable. Costs incurred by us for gathering and transportation from the wellhead through the processing facilities are recognized as a component of GPT expenses.

Marketing services. We provide marketing services to certain of our joint venture partners and other third parties with respect to oil and gas production for which we are the operator. Pricing for such services represents a negotiated fixed rate fee based on the sales price of the underlying oil and gas products. Production attributable to joint venture partners from wells that we operate that are not subject to marketing agreements are delivered in kind. Marketing revenue is recognized simultaneously with the sale of our commodity production to our customers. Direct costs associated with our marketing efforts are included in G&A expenses.

Share-Based Compensation

Our stock compensation plans permit the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. We measure the cost of employee services received in exchange for an award of equity-classified instruments based on the grant-date fair value of the award. Compensation cost associated with the liability-classified awards is measured at the end of each reporting period and recognized based on the period of time that has elapsed during the applicable performance period.

4. Bankruptcy Proceedings, Emergence and Fresh Start Accounting

Bankruptcy Proceedings and Emergence

On May 12, 2016 (the "Petition Date"), we and eight of our subsidiaries (the "Chapter 11 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 (the "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 "Emergence Date").

On November 20, 2018, the Bankruptcy Court issued a final decree to close the case.

Debtors-In-Possession. From the Petition Date through the Emergence Date, we and the Chapter 11 Subsidiaries operated our business as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court granted all "first day" motions filed by us and the Chapter 11 Subsidiaries, which were designed primarily to minimize the impact of the bankruptcy proceedings on our normal day-to-day operations, our customers, regulatory agencies, including taxing authorities, and employees. As a result, we were able to conduct normal business activities and pay all associated obligations for the post-petition period and we were also authorized to pay and have paid (subject to limitations applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders, amounts due to taxing authorities for production and other related taxes and funds belonging to third parties, including royalty and working interest holders.

Pre-Petition Agreements. Immediately prior to the Petition Date, the holders (the "Ad Hoc Committee") of approximately 86 percent of the $1,075 million principal amount of our 7.25% Senior Notes due 2019 (the "2019 Senior Notes") and 8.50% Senior Notes due 2020 (the "2020 Senior Notes" and, together with the 2019 Senior Notes, the "Senior Notes") agreed to a restructuring support agreement (the "RSA") that set forth the general framework of the Plan and the timeline for the bankruptcy proceedings. In addition, we entered into a backstop commitment agreement (the "Backstop Commitment Agreement") with the parties thereto (collectively, the "Backstop Parties"), pursuant to which the Backstop Parties committed to provide a $50 million commitment to backstop a rights offering (the "Rights Offering") that was conducted in connection with the Plan.

Plan of Reorganization. Pursuant to the terms of the Plan, which was supported by us, the holders (the "RBL Lenders") of 100 percent of the claims attributable to our pre-petition credit agreement (as amended, the "RBL"), the Ad Hoc Committee and the Official Committee of Unsecured Claimholders (the "UCC"), the following transactions were completed subsequent to the Confirmation Date and prior to or at the Emergence Date:

- the approximately $1,122 million of indebtedness, including accrued interest, attributable to our Senior Notes and certain other unsecured claims were exchanged for 6,069,074 shares representing 41 percent of the Successor's common stock ("Successor Common Stock");
- a total of $50 million of proceeds were received on the Emergence Date from the Rights Offering resulting in the issuance of 7,633,588 shares representing 51 percent of Successor Common Stock to holders of claims arising under the Senior Notes, certain holders of general unsecured claims and to the Backstop Parties;
- the Backstop Parties received a backstop fee comprised of 472,902 shares representing three percent of Successor Common Stock;
- an additional 816,454 shares representing five percent of Successor Common Stock were authorized for disputed general unsecured claims and non-accredited investor holders of the Senior Notes and subsequently, 749,600 shares of Successor Common Stock were reserved for issuance under a new management incentive plan;
- on the Emergence Date, we entered into a shareholders agreement and a registration rights agreement and amended our articles of incorporation and bylaws for the authorization of the Successor Common Stock and to provide customary registration rights thereunder, among other corporate governance actions;
- holders of claims arising under the RBL were paid in full from cash on hand, $75.4 million from borrowings under a new credit agreement (the "Credit Facility") (see Note 10 below) and proceeds from the Rights Offering;

- the debtor-in-possession credit facility (the “DIP Facility”), under which there were no outstanding borrowings at any time from the Petition Date through the Emergence Date, was canceled and less than $0.1 million in fees were paid in full in cash;
- certain other priority claims were paid in full in cash, reinstated or otherwise treated in a manner acceptable to the creditor claim-holders;
- a cash reserve of $2.7 million was established for certain other secured, priority or convenience claims pending resolution as of the Emergence Date;
- an escrow account for professional service fees attributable to our advisers and those of the UCC was funded by us with cash of $14.6 million, and we paid $7.2 million for professional fees and expenses on behalf of the RBL Lenders, the Ad Hoc Committee and the indenture trustee for the Senior Notes;
- on the Emergence Date, our previous interim Chief Executive Officer, Edward B. Cloues, resigned and each member of our board of directors resigned and was replaced by new board members;
- our Predecessor preferred stock and common stock was canceled, extinguished and discharged; and
- all of our Predecessor share-based compensation plans and supplemental employee retirement plan (the “SERP”) entitlements were canceled.

Fresh Start Accounting

We adopted Fresh Start Accounting on the Emergence Date in connection with our emergence from bankruptcy. As referenced below, our reorganization value of $334.0 million, immediately prior to emergence was substantially less than our post-petition liabilities and allowed claims. Furthermore and 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 Common Stock was issued to the Predecessor’s creditors, primarily former holders of our Senior Notes. Accordingly, the holders of the Predecessor’s common and preferred shares effectively received no shares of the Successor. The adoption of Fresh Start Accounting results in a new reporting entity, the Successor, for financial reporting purposes. The presentation is analogous to that of a new business entity such that the Successor is presented with no beginning retained earnings or deficit on the Emergence Date.

Reorganization Value

Reorganization value represents the fair value of the Successor’s total assets prior to the consideration of liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after a restructuring. The reorganization value, which was derived from the Successor’s enterprise value, was allocated to our individual assets based on their estimated fair values.

Enterprise value represents the estimated fair value of an entity’s long term debt and shareholders’ equity. The Successor’s enterprise value, as approved by the Bankruptcy Court in support of the Plan, was estimated to be within a range of $218 million to $382 million with a mid-point value of $300 million. Based on the estimates and assumptions utilized in our Fresh Start Accounting process, we estimated the Successor’s enterprise value to be approximately $266.2 million after the consideration of cash and cash equivalents on hand at the Emergence Date.

The following table reconciles the enterprise value, net of cash and cash equivalents, to the estimated fair value of our Successor Common Stock as of the Emergence Date:

Enterprise value	$	234,831
Plus: Cash and cash equivalents		31,414
Less: Fair value of debt		(75,350)
Fair value of Successor Common Stock	$	190,895
Shares outstanding as of September 12, 2016		14,992,018
Per share value	$	12.73

The following table reconciles the enterprise value to the reorganization value of our Successor assets as of the Emergence Date:

Enterprise value	$	234,831
Plus: Cash and cash equivalents		31,414
Plus: Current liabilities		54,171
Plus: Noncurrent liabilities excluding long-term debt		13,558
Reorganization value	$	333,974

Valuation Process

Our valuation analysis was prepared with the assistance of an independent third-party consultant utilizing reserve information prepared by our independent reserve engineers, internal development plans and schedules, other internal financial information and projections and the application of standard valuation techniques including risked net asset value analysis and comparable public company metrics. Because many of the inputs utilized in the valuation process are not observable, we have classified the Fresh Start fair value measurements as Level 3 inputs as that term is defined in GAAP.

Our principal assets include the Successor's oil and gas properties. We determined the fair value of our oil and gas properties based on the discounted cash flows expected to be generated from these assets. Our analyses were based on market conditions and reserves in place as confirmed by our independent petroleum engineers. The proved reserves were segregated into various geographic regions, including sub-regions within the Eagle Ford where a substantial portion of our assets are located, for which separate risk factors were determined based on geological characteristics. Due to the limited drilling plans that we had in place, proved undeveloped locations were risked accordingly. Future cash flows were estimated by using New York Mercantile Exchange ("NYMEX") forward prices for West Texas Intermediate ("WTI") crude oil and Henry Hub natural gas with inflation adjustments applied to periods beyond a five-year horizon. These prices were adjusted for differentials realized by us for location and product quality. Gathering and transportation costs were estimated based on agreements that we had in place and development and operating costs were based on our most recent experience and adjusted for inflation in future years. The risk-adjusted after-tax cash flows were discounted at a rate of 13.5%. This rate was determined from a weighted-average cost of capital computation which utilized a blended expected cost of debt and expected returns on equity for similar industry participants. Plugging and abandonment costs were also identified and measured in this process in order to determine the fair value of the Successor's AROs attributable to our proved developed reserves on the Emergence Date. Based on this valuation process, we determined fair values of $121.9 million for our proved reserves and $2.7 million for the related AROs.

With respect to the valuation of our undeveloped acreage, we segregated our current lease holdings in the Eagle Ford into prospect regions in which we had significant developed acreage and those in which we had not yet initiated any significant drilling activity. For those prospects within previously developed regions, we applied a multiple based on recent transactions involving acreage deemed comparable to our acreage for each targeted formation. Based on this valuation process, we determined a fair value of $92.5 million for our undeveloped acreage within previously developed regions of the Eagle Ford. For those lease holdings in other areas of the Eagle Ford, we disregarded those prospects for which lease expirations were to occur during 2016 as well as those for which future drilling was considered uneconomical at then current commodity prices. A reduced multiple was then applied to this adjusted undeveloped acreage consistent with recent transactions for acreage deemed comparable to our acreage resulting in a fair value of $8.3 million. We attributed no value to our limited undeveloped lease holdings in all areas other than the Eagle Ford.

Our remaining equipment and other fixed assets were valued at $26.7 million primarily using a cost approach that incorporated depreciation and obsolescence to the extent applicable on an asset-by-asset basis. The most significant of these assets is our water facility in South Texas which is integral to our regional operations. Accordingly, this asset, for which we determined a fair value of $23.4 million, is included in our full cost pool for purposes of determining our DD&A attributable to our oil and gas production. Certain assets, particularly personal property including office equipment and vehicles, among others, were valued based on market data for comparable assets to the extent such information was available.

The remaining reorganization value is attributable to certain natural gas imbalance receivables, cash and cash equivalents, working capital assets including accounts receivable, prepaid items, current derivative assets and debt issuance costs. Our natural gas imbalance receivables, which are fully attributable to our Mid-Continent operations in the Granite Wash, were valued using NYMEX spot prices for Henry Hub natural gas adjusted for basis differentials for transportation. Our accounts receivable, including amounts receivable from our joint venture partners, were subjected to analysis on an individual basis and reserved to the extent we believe was appropriate. Collectively, these remaining assets, including our current derivative assets which are marked-to-market on a monthly basis, were stated at their fair values on the Emergence Date. The reorganization value also included $3.0 million of issuance costs attributable to the Credit Facility under which we initially borrowed $75.4 million. This amount was capitalized in accordance with GAAP as it represents costs attributable to the access to credit over the term of the Credit Facility.

Our liabilities on the Emergence Date included the aforementioned borrowings under the Credit Facility, working capital liabilities including accounts payable and accrued liabilities, a reserve for certain litigation matters, pension and health care obligations attributable to certain retirees, AROs, and derivative liabilities. As the Credit Facility is current and is a variable-rate financial instrument, it was stated at its fair value. Our working capital liabilities and litigation reserve are ordinary course obligations and their carrying amounts approximated their fair values. We revalued our retiree obligations based on data from our independent actuaries and they have been stated at their fair values. The AROs were valued in connection with the valuation process attributable to our oil and gas reserves as discussed above. Finally, our derivative liabilities were also stated at their fair value as they are marked-to-market on a monthly basis.

Successor Balance Sheet

The following table reflects the reorganization and application of Fresh Start Accounting adjustments on our Consolidated Balance Sheet as of September 12, 2016:

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
Assets						
Current assets						
Cash and cash equivalents	$ 48,718	$ (17,304)	(1)	$ —		$ 31,414
Accounts receivable, net of allowance for doubtful accounts	35,606	4,292	(2)	—		39,898
Derivative assets	397	—		—		397
Other current assets	3,966	(832)	(3)	—		3,134
Total current assets	88,687	(13,844)		—		74,843
Property and equipment, net	309,261	—		(55,751)	(12)	253,510
Other assets	6,902	(1,281)	(4)	—		5,621
Total assets	$ 404,850	$ (15,125)		$ (55,751)		$ 333,974
Liabilities and Shareholders' Equity (Deficit)						
Current liabilities						
Accounts payable and accrued liabilities	$ 77,151	$ (21,166)	(5)	$ (3,455)	(13)	$ 52,530
Derivative liabilities	1,641	—		—		1,641
Current maturities of long-term debt	113,653	(113,653)	(6)	—		—
Total current liabilities	192,445	(134,819)		(3,455)		54,171
Other liabilities	84,953	100	(5)	(80,615)	(14)	4,438
Derivative liabilities	9,120	—		—		9,120
Long-term debt	—	75,350	(7)	—		75,350
Liabilities subject to compromise	1,154,163	(1,154,163)	(8)	—		—
Shareholders' equity (deficit)						
Preferred stock (Predecessor)	1,880	(1,880)	(9)	—		—
Common stock (Predecessor)	697	(697)	(9)	—		—
Paid-in capital (Predecessor)	1,213,797	(1,213,797)	(9)	—		—
Deferred compensation obligation (Predecessor)	3,440	(3,440)	(9)	—		—
Accumulated other comprehensive income (Predecessor)	383	(383)	(9)	—		—
Treasury stock (Predecessor)	(3,574)	3,574	(9)	—		—
Common stock (Successor)	—	150	(10)	—		150
Paid-in capital (Successor)	—	190,745	(10)	—		190,745
Accumulated deficit	(2,252,454)	2,224,135	(11)	28,319	(15)	—
Total shareholders' equity (deficit)	(1,035,831)	1,198,407		28,319		190,895
Total liabilities and shareholders' equity (deficit)	$ 404,850	$ (15,125)		$ (55,751)		$ 333,974

Reorganization Adjustments

1. Represents the net cash payments that occurred on the Emergence Date:

Sources:				
Proceeds from the Credit Facility	$	75,350		
Proceeds from the Rights Offering, net of issuance costs		49,943		
Total sources			$	125,293
Uses:				
Repayment of RBL	$	113,653		
Accrued interest payable on RBL		1,374		
DIP Facility fees		12		
Debt issue costs of the Credit Facility		3,011		
Funding of professional fee escrow account		14,575		
RBL lender professional fees and expenses		455		
Ad Hoc Committee and indenture trustee professional fees and expenses		6,782		
Payment of certain allowed claims and settlements		2,735		
Total uses				142,597
			$	(17,304)

2. Represents the reclassification of SERP assets to a current receivable from other noncurrent assets upon the cancellation of the underlying plan and the reversion of the assets to the Successor.
3. Represents the write-off of certain prepaid directors and officers tail insurance.
4. Represents the capitalization of debt issuance costs attributable to the Credit Facility, net of the reclassification of SERP assets as discussed in item (2) above.
5. Represents the payment of professional fees on behalf of the RBL Lenders, the Ad Hoc Committee and the UCC, indenture trustee fees and expenses, interest payable on the RBL as well as certain allowed claims and settlements net of the establishment of reserves and the reinstatement of certain other obligations.
6. Represents the repayment of the RBL in cash in full.
7. Represents the initial borrowings under the Credit Facility.
8. Liabilities subject to compromise were settled as follows in accordance with the Plan:

Liabilities subject to compromise prior to the Emergence Date:				
Senior Notes	$	1,075,000		
Interest on Senior Notes		47,213		
Firm transportation obligation		11,077		
Compensation – related		9,733		
Deferred compensation		4,676		
Trade accounts payable		1,487		
Litigation claims		1,092		
Other accrued liabilities		3,885		
			$	1,154,163
Amounts settled in cash, reinstated or otherwise reserved at emergence				(3,915)
Gain on settlement of liabilities subject to compromise			$	1,150,248

9. Represents the cancellation of our Predecessor preferred and common stock and related components of our Predecessor shareholders' deficit.
10. Represents the issuance of 14,992,018 shares of Successor Common Stock with a fair value of $12.73 per share.

11. Represents the cumulative impact of the reorganization adjustments described above:

Gain on settlement of liabilities subject to compromise		$	1,150,248
Fair value of equity allocated to:			
Unsecured creditors on the Emergence Date	174,477		
Unsecured creditors pending resolution on the Emergence Date	10,396		
Backstop Parties in the form of a Commitment Premium	6,022		
			190,895
Cancellation of Predecessor shareholders' deficit			882,992
Net impact to Predecessor accumulated deficit		$	2,224,135

Fresh Start Adjustments

12. Represents the Fresh Start Accounting valuation adjustments applied to our oil and gas properties and other equipment.
13. Represents the accelerated recognition of the current portion of previously deferred gains on sales of assets attributable to the accounting presentation required by GAAP under the Predecessor.
14. Represents the recognition of Fresh Start Accounting adjustments to: (i) our AROs attributable to the revalued oil and gas properties and (ii) our retiree obligations based on actuarial measurements, as well as the accelerated recognition of the noncurrent portion of previously deferred gains on sales of assets attributable to the accounting presentation required by GAAP under the Predecessor.
15. Represents the cumulative impact of the Fresh Start Accounting adjustments discussed above.

Reorganization Items. As described above in Note 2, our Consolidated Statements of Operations for the period ended September 12, 2016 include "Reorganization items, net," which reflects gains recognized on the settlement of liabilities subject to compromise and costs and other expenses associated with the bankruptcy proceedings, principally professional fees, and the costs associated with the DIP Facility. These post-petition costs for professional fees, as well as administrative fees charged by the U.S. Trustee, have been reported in "Reorganization items, net" in our Consolidated Statement of Operations as described above. Similar costs that were incurred during the pre-petition periods have been reported in "General and administrative" expenses.

While we emerged from bankruptcy in September 2016, certain administrative and claims resolution activities continued until November 2018 when the Bankruptcy Court issued a final decree which effectively closed the case. Upon the closure, we reversed the $0.2 million remaining unused portion of an accrual that was established on the Emergence Date for legal and professional fees and administrative costs. In addition, we reversed the $2.7 million unallocated portion of a reserve that was established on the Emergence Date for the potential settlement of certain claims in cash. Finally, we also reversed $0.4 million of accounts payable that were held open since the Emergence Date as secured claims, but were ultimately expunged. As these items of income are directly attributable to the final administration of our bankruptcy case and not a part of our continuing operations, they are classified on our Consolidated Statement of Operations as components of "Reorganization items, net."

The following table summarizes the components included in "Reorganization items, net" in our Consolidated Statements of Operations for the period presented:

	Year Ended December 31, 2018	January 1 Through September 12, 2016
Gains on the settlement of liabilities subject to compromise	$ —	$ 1,150,248
Fresh start accounting adjustments	—	28,319
Legal and professional fees and expenses	200	(29,976)
Settlements attributable to contract amendments	—	(2,550)
DIP Facility costs and commitment fees	—	(170)
Write-off of prepaid directors and officers insurance	—	(832)
Other reorganization items	3,122	(46)
	$ 3,322	$ 1,144,993

5. Acquisitions and Divestitures

Acquisitions

Hunt Acquisition

In December 2017, we entered into a purchase and sale agreement with Hunt Oil Company ("Hunt") to acquire certain oil and gas assets in the Eagle Ford Shale, primarily in Gonzales County, Texas for $86.0 million in cash, subject to adjustments (the "Hunt Acquisition"). The Hunt Acquisition had an effective date of October 1, 2017 and closed on March 1, 2018, at which time we paid cash consideration of $84.4 million. In connection with the Hunt Acquisition, we also acquired working interests in certain wells that we previously drilled as operator in which Hunt had rights to participate prior to the transaction closing. Accumulated costs, net of suspended revenues for these wells was $13.8 million, which we have reflected as a component of total net assets acquired. We funded the Hunt Acquisition with borrowings under the Credit Facility.

The final settlement of the Hunt Acquisition occurred in July 2018, at which time an additional $0.2 million of acquisition costs was allocated from certain working capital components and Hunt transferred $1.4 million to us primarily for suspended revenues attributable to the acquired properties.

We incurred a total of $0.5 million of transaction costs for legal, due diligence and other professional fees associated with the Hunt Acquisition, including $0.1 million in 2017 and $0.4 million in the first quarter of 2018. These costs have been recognized as a component of our G&A expenses.

We accounted for the Hunt Acquisition by applying the acquisition method of accounting as of March 1, 2018. The following table represents the final fair values assigned to the net assets acquired and the total acquisition cost incurred, including consideration transferred to Hunt:

Assets		
Oil and gas properties - proved	$	82,443
Oil and gas properties - unproved		16,339
Liabilities		
Revenue suspense		1,448
Asset retirement obligations		356
Net assets acquired	$	96,978
Cash consideration paid to Hunt, net	$	82,955
Application of working capital adjustments		245
Accumulated costs, net of suspended revenues, for wells in which Hunt had rights to participate		13,778
Total acquisition costs incurred	$	96,978

Devon Acquisition

In July 2017, we entered into a purchase and sale agreement (the "Purchase Agreement"), with Devon Energy Corporation ("Devon") to acquire all of Devon's right, title and interest in and to certain oil and gas assets (the "Devon Properties"), including oil and gas leases covering approximately 19,600 net acres located primarily in Lavaca County, Texas for aggregate consideration of $205 million in cash (the "Devon Acquisition"). Upon execution of the Purchase Agreement, we deposited $10.3 million as earnest money into an escrow account (the "Escrow Account"). The Devon Acquisition had an effective date of March 1, 2017 and closed on September 29, 2017, at which time we paid cash consideration of $189.9 million and $7.1 million was released from the Escrow Account to Devon. In November 2017, we acquired additional working interests in the Devon Properties for $0.7 million from parties that had tag-along rights to sell their interests under the Purchase Agreement.

As of December 31, 2017, $3.2 million remained in the Escrow Account, which was included as a component of noncurrent "Other assets" on our Consolidated Balance Sheet. The final settlements of the Devon Acquisition together with the tag-along rights acquisition, occurred in February 2018, at which time $2.5 million in cash was transferred from the Escrow Account to Devon, and the remaining $0.7 million was distributed to us. In addition, Devon transferred $0.4 million to us for suspended revenues attributable to the acquired properties.

The Devon Acquisition was financed with the net proceeds received from borrowing under the $200 million Second Lien Credit Agreement dated as of September 29, 2017 (the "Second Lien Facility") (see Note 10 for terms of the Second Lien Facility) and incremental borrowings under the Credit Facility.

We incurred a total of $1.3 million of transaction costs associated with the Devon Acquisitions during 2017, including advisory, legal, due diligence and other professional fees. These costs have been recognized as a component of our G&A expenses.

We accounted for the Devon Acquisition by applying the acquisition method of accounting as of the Date of Acquisition. The following table represents the final fair values assigned to the net assets acquired and the total consideration transferred:

Assets		
Oil and gas properties - proved	$	42,866
Oil and gas properties - unproved		146,686
Other property and equipment		8,642
Liabilities		
Revenue suspense		355
Asset retirement obligations		494
Net assets acquired	$	197,345
Cash consideration paid to Devon and tag-along parties, net	$	190,277
Amount transferred to Devon from the Escrow Account		9,519
Application of working capital adjustments, net		(2,451)
Total consideration	$	197,345

Valuation of Acquisitions

The fair values of the oil and gas properties acquired in the Hunt and Devon Acquisitions were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future cash flows (v) the timing of or development plans and (vi) a market-based weighted-average cost of capital. The fair value of the other property and equipment acquired was measured primarily with reference to replacement costs for similar assets adjusted for the age and normal use of the underlying assets. Because many of these inputs are not observable, we have classified the initial fair value estimates as Level 3 inputs as that term is defined in GAAP.

Impact of Acquisitions on Actual and Pro Forma Results of Operations

The results of operations attributable to the Hunt and Devon Acquisitions have been included in our Consolidated Financial Statements for the periods after March 1, 2018 and September 30, 2017, respectively. The Devon Acquisition provided revenues and estimated earnings, excluding allocations of interest expense and income taxes, of approximately $9 million and $4 million, respectively, for the period from October 1, 2017 through December 31, 2017. The Hunt Acquisition provided revenues and estimated earnings, excluding allocations of interest expense and income taxes, of approximately $0.4 million and $0.2 million, respectively, for the period from March 1, 2018 through March 31, 2018. As the properties and working interests acquired in connection with the Hunt and Devon Acquisitions are included within our existing Eagle Ford acreage, it is not practical or meaningful to disclose revenues and earnings unique to those assets for periods beyond those during which they were acquired, as they were fully integrated into our regional operations soon after their acquisition.

The following table presents unaudited summary pro forma financial information for the years ended December, 31, 2018 and 2017 assuming the Hunt and Devon Acquisitions and the related entry into the Second Lien Facility occurred as of January 1, 2017. The pro forma financial information does not purport to represent what our actual results of operations would have been if the Hunt and Devon Acquisitions and the entry into the Second Lien Facility had occurred as of this date, or the results of operations for any future periods. We have excluded any pro forma presentations for the Successor and Predecessor periods in 2016 as the determination of such pro forma adjustments are not practical due primarily to our reorganization and the adoption of Fresh Start Accounting and the full cost method on the Emergence Date. In light of these circumstances, we also believe that such a pro forma presentation for 2016 would not be comparable and could potentially be misleading.

	Year Ended December 31,			
	2018		2017	
Total revenues	$	446,077	$	209,015
Net income attributable to common shareholders	$	227,930	$	30,861
Net income per share - basic	$	15.14	$	2.06
Net income per share - diluted	$	14.91	$	2.05

Divestitures

Mid-Continent Divestiture

In June 2018, we entered into a purchase and sale agreement with a third party to sell all of our remaining Mid-Continent oil and gas properties, located primarily in Oklahoma in the Granite Wash, for $6.0 million in cash, subject to customary adjustments. The sale had an effective date of March 1, 2018 and closed on July 31, 2018, and we received proceeds of $6.2 million. The sale proceeds and de-recognition of certain assets and liabilities were recorded as a reduction of our net oil and gas properties. In November 2018, we paid $0.5 million, including $0.2 million of suspended revenues, to the buyer in connection with the final settlement.

The Mid-Continent properties had asset retirement obligations (“AROs”) of $0.3 million as well as a net working capital deficit attributable to the oil and gas properties of $1.3 million as of July 31, 2018. The net pre-tax operating income attributable to the Mid-Continent assets was $1.6 million and $2.2 million for the years ended December 31, 2018 and December 31, 2017, respectively.

Sales of Undeveloped Acreage, Rights and Other Assets

In February 2018, we sold our undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana that were scheduled to expire in 2019. In March 2018, we sold certain undeveloped deep leasehold rights in Oklahoma, and in May 2018, we sold certain pipeline assets in our former Marcellus Shale operating region. We received a combined total of $1.7 million for these leasehold and other assets which were applied as a reduction of our net oil and gas properties.

6. Accounts Receivable and Major Customers

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

	December 31,	
	2018	2017
Customers	$ 59,030	$ 39,106
Joint interest partners	6,404	32,493
Other	640	584
	66,074	72,183
Less: Allowance for doubtful accounts	(36)	(2,362)
	$ 66,038	$ 69,821

For the year ended December 31, 2018, three customers accounted for $304.3 million, or approximately 69% of our consolidated product revenues. The revenues generated from these customers during 2018 were $173.0 million, $71.5 million and $59.8 million or 39%, 16%, and 14% of the consolidated total, respectively. As of December 31, 2018, $28.6 million, or approximately 48% of our consolidated accounts receivable from customers was related to these customers. For the year ended December 31, 2017, three customers accounted for $137.5 million, or approximately 86% of our consolidated product revenues. The revenues generated from these customers during 2017 were $94.1 million, $22.1 million and $21.3 million, or approximately 59%, 14% and 13% of the consolidated total, respectively. As of December 31, 2017, $32.1 million, or approximately 82% 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.

Revenue from Contracts with Customers

Adoption of ASC Topic 606

Effective January 1, 2018, we adopted ASC Topic 606 and have applied the guidance therein to our contracts with customers for the sale of commodity products (crude oil, NGLs and natural gas) as well as marketing services that we provide to our joint venture partners and other third parties. ASC Topic 606 provides for a five-step revenue recognition process model to determine the transfer of goods or services to consumers in an amount that reflects the consideration to which we expect to be entitled in exchange for such goods and services.

Upon the adoption of ASC Topic 606, we: (i) changed the presentation of our NGL product revenues from a gross basis to a net basis and changed the classification of certain natural gas processing costs associated with NGLs from a component of “Gathering, processing and transportation” (“GPT”) expense to a reduction of NGL product revenues as described in further detail below, (ii) wrote off $2.7 million of accounts receivable arising from natural gas imbalances accounted for under the entitlements method as a direct reduction to our beginning balance of retained earnings as of January 1, 2018, and (iii) adopted the sales method with respect to production imbalance transactions beginning after December 31, 2017.

The following table illustrates the impact of the adoption of ASC Topic 606 on our Condensed Consolidated Statement of Operations for the year ended December 31, 2018:

	Year Ended December 31, 2018		
	As Determined Under Prior GAAP	As Reported Under ASC Topic 606	Net Change
Revenues			
Crude oil	$ 402,485	$ 402,485	$ —
Natural gas liquids	$ 23,429	$ 21,073	$ (2,356)
Natural gas	$ 15,972	$ 15,972	$ —
Marketing services (included in Other revenues, net)	$ 523	$ 523	$ —
Operating expenses			
Gathering, processing and transportation	$ 20,982	$ 18,626	$ (2,356)
Net income	$ 224,785	$ 224,785	$ —

Transaction Prices, Contract Balances and Performance Obligations

Substantially all of our commodity product sales are short-term in nature with contract terms of one year or less. Accordingly, we have applied the practical expedient included in ASC Topic 606, which provides for an exemption from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Under our commodity product sales contracts, we bill our customers and recognize revenue when our performance obligations have been satisfied as described above. At that time, we have determined that payment is unconditional. Accordingly, our commodity sales contracts do not create contract assets or liabilities as those terms are defined in ASC Topic 606.

We record revenue in the month that our oil and gas production is delivered to our customers. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

7. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to commodity price volatility. Our derivative instruments are not formally designated as hedges in the context of U.S. 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 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 collar contract.

We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for WTI crude oil and LLS 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.

We terminated all of our pre-petition derivative contracts from March 2016 through May 2016 for $63.0 million and reduced our amounts outstanding under the RBL by $52.0 million. In connection with these transactions, the counterparties to the derivative contracts, which were also affiliates of lenders under the RBL, transferred the cash proceeds that were used for RBL repayments directly to the administrative agent under the RBL. Accordingly, all of these RBL repayments have been presented as non-cash financing activities in our Consolidated Statement of Cash Flows for the period January 1, 2016 through September 12, 2016.

The following table sets forth our commodity derivative positions as of December 31, 2018:

	Instrument	Average Volume Per Day	Weighted Average Price	Fair Value Asset	Fair Value Liability
Crude Oil:		**(barrels)**	**($/barrel)**		
First quarter 2019	Swaps-WTI	6,446	$ 54.46	$ 4,959	$ —
First quarter 2019	Swaps-LLS	5,000	$ 59.17	3,684	—
Second quarter 2019	Swaps-WTI	6,421	$ 54.48	4,307	—
Second quarter 2019	Swaps-LLS	5,000	$ 59.17	3,203	—
Third quarter 2019	Swaps-WTI	6,397	$ 54.50	3,821	—
Third quarter 2019	Swaps-LLS	5,000	$ 59.17	3,092	—
Fourth quarter 2019	Swaps-WTI	6,398	$ 54.50	3,498	—
Fourth quarter 2019	Swaps-LLS	5,000	$ 59.17	3,015	—
First quarter 2020	Swaps-WTI	6,000	$ 54.09	2,807	—
Second quarter 2020	Swaps-WTI	6,000	$ 54.09	2,609	—
Third quarter 2020	Swaps-WTI	6,000	$ 54.09	2,450	—
Fourth quarter 2020	Swaps-WTI	6,000	$ 54.09	2,234	—
Settlements to be received in subsequent period, net				4,362	

Financial Statement Impact of Derivatives

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

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Derivative gains (losses)	$ 37,427	$ (17,819)	$ (16,622)	$ (8,333)

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 Consolidated Statements of Cash Flows under the "Net losses (gains)" and "Cash settlements, net."

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

		Fair Values			
		December 31, 2018		December 31, 2017	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ 34,932	$ 991	$ —	$ 27,777
Commodity contracts	Derivative assets/liabilities – noncurrent	10,100	—	—	13,900
		$ 45,032	$ 991	$ —	$ 41,677

As of December 31, 2018, we reported net commodity derivative assets of $44.0 million. The contracts associated with this position are with eight 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.

8. Property and Equipment

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

	December 31, 2018	December 31, 2017
Oil and gas properties:		
Proved	$ 1,037,993	$ 460,029
Unproved	63,484	117,634
Total oil and gas properties	1,101,477	577,663
Other property and equipment	20,383	12,712
Total property and equipment	1,121,860	590,375
Accumulated depreciation, depletion and amortization	(193,866)	(61,316)
	$ 927,994	$ 529,059

Unproved property costs of $63.5 million and $117.6 million have been excluded from amortization as of December 31, 2018 and December 31, 2017, respectively. We transferred $82.8 million and $40.4 million of undeveloped leasehold costs, including capitalized interest, associated with proved undeveloped reserves, acreage unlikely to be drilled or expiring acreage, from unproved properties to the full cost pool during the years ended December 31, 2018 and 2017, respectively. We capitalized internal costs of $3.7 million and $2.4 million and interest of $9.1 million and $2.7 million during the year ended December 31, 2018 and 2017, respectively, in accordance with our accounting policies. Average DD&A per barrel of oil equivalent of proved oil and gas properties was $16.11 and $12.87 for the years ended December 31, 2018 and 2017, $11.21 for the Successor period from September 13, 2016 through December 31, 2016, and $10.04 for the Predecessor period from January 1, 2016 through September 12, 2016. The DD&A rate for the Predecessor period was determined under the successful efforts method while the Successor periods subsequent to September 12, 2016 were determined under the full cost method (see Note 2).

9. Asset Retirement Obligations

The following table reconciles our AROs as of the dates presented, which are included in the “Other liabilities” caption on our Consolidated Balance Sheets:

	Year Ended December 31, 2018	Year Ended December 31, 2017
Balance at beginning of period	$ 3,286	$ 2,459
Changes in estimates	354	149
Liabilities incurred	335	118
Liabilities settled	(8)	(139)
Purchase of properties	385	494
Sale of properties	(310)	—
Accretion expense	272	205
Balance at end of period	$ 4,314	$ 3,286

10. Long-Term Debt

The following table summarizes our long-term debt as of the dates presented:

	December 31, 2018		December 31, 2017	
	Principal	Unamortized Discount and Issuance Costs [1]	Principal	Unamortized Discount and Issuance Costs [1]
Credit facility [2]	$ 321,000		$ 77,000	
Second lien term loans	200,000	$ 9,625	200,000	$ 11,733
Totals	521,000	9,625	277,000	11,733
Less: Unamortized discount	(3,159)		(3,839)	
Less: Unamortized deferred issuance costs	(6,466)		(7,894)	
Long-term debt, net	$ 511,375		$ 265,267	

[1] Discount and issuance costs of the Second Lien Facility are being amortized over the term of the underlying loan using the effective-interest method.

[2] Issuance costs of the Credit Facility, which represent costs attributable to the access to credit over its contractual term, have been presented as a component of Other assets (see Note 13) and are being amortized over the term of the Credit Facility using the straight-line method.

Credit Facility

On the Emergence Date, we entered into the Credit Facility. The Credit Facility provides for a $450.0 million revolving commitment and borrowing base and a $5 million sublimit for the issuance of letters of credit. On October 26, 2018, we entered into the Master Assignment, Agreement and Amendment No. 5 to the Credit Facility (the "Fifth Amendment") whereby the borrowing base was redetermined from $340.0 million to $450.0 million. In the years ended December 31, 2018 and December 31, 2017, we paid and capitalized issue costs of $0.9 million and $1.7 million, respectively in connection with amendments to the Credit Facility and wrote-off $0.8 million during 2017 of previously capitalized issue costs due to changes in the composition of financial institutions comprising the Credit Facility bank group associated with that amendment. The availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base. The borrowing base under the Credit Facility is generally redetermined semi-annually in April and October of each year. Additionally, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us for general corporate purposes including working capital. The Credit Facility matures in September 2020. We had $0.4 million and $0.8 million in letters of credit outstanding as of December 31, 2018 and December 31, 2017, respectively.

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 the election of the borrower, and is computed on the basis of a year of 360 days. As of December 31, 2018, the actual interest rate on the outstanding borrowings under the Credit Facility was 5.96%. 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, of 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.

As of December 31, 2018, and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of the covenants under the Credit Facility.

Second Lien Facility

On September 29, 2017, we entered into the $200 million Second Lien Facility. We received net proceeds of $ 187.8 million from the Second Lien Facility net of an original issue discount (“OID”) of $4.0 million and issue costs of $8.2 million. The proceeds from the Second Lien Facility were used to fund the Devon Acquisition and related fees and expenses. The maturity date under the Second Lien Facility is September 29, 2022.

The outstanding borrowings under the Second Lien Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate based on the prime rate plus an applicable margin of 6.00% or (b) a customary LIBOR rate plus an applicable margin of 7.00%. As of December 31, 2018, the actual interest rate of outstanding borrowings under the Second Lien Facility was 9.53%. Amounts under the Second Lien Facility were borrowed at a price of 98% with an initial interest rate of 8.34% resulting in an effective interest rate of 9.89%. 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 eurocurrency borrowings is payable every one or three months (including in three month intervals if we select a six month interest period), at our election and is computed on the basis of a 360-day year. We have the right, to the extent permitted under the Credit Facility and an intercreditor agreement between the lenders under the Credit Facility and the lenders under the Second Lien Facility, to prepay loans under the Second Lien Facility at any time, subject to the following prepayment premiums (in addition to customary “breakage” costs with respect to eurocurrency loans): during year one, a customary “make-whole” premium; during year two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium. The Second Lien Facility also provides for the following prepayment premiums in the event of a change in control that results in an offer of prepayment that is accepted by the lenders under the Second Lien Facility: during years one and two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of the Company’s and its subsidiaries’ assets with lien priority subordinated to the liens securing the Credit Facility. The obligations under the Second Lien Facility are guaranteed by us and the Subsidiary Guarantors.

The Second Lien Facility has no financial covenants, but 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 and transactions with affiliates and other customary covenants.

As illustrated in the table above, the OID and issue costs of the Second Lien Facility are presented as reductions to the outstanding term loans. These costs are subject to amortization using the interest method over the five-year term of the Second Lien Facility.

As of December 31, 2018, and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of the covenants under the Second Lien Facility.

11. Income Taxes

The following table summarizes our provision for income taxes for the periods presented:

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Current income taxes (benefit)				
Federal	$ (2,471)	$ —	$ —	$ —
	(2,471)	—	—	—
Deferred income taxes (benefit)				
Federal	2,471	(4,943)	—	—
State	523	—	—	—
	2,994	(4,943)	—	—
	$ 523	$ (4,943)	$ —	$ —

The following table reconciles the difference between the income tax expense (benefit) computed by applying the statutory tax rate to our income (loss) before income taxes and our reported income tax benefit for the periods presented:

	Successor						Predecessor	
	Year Ended December 31,				September 13 Through December 31,		January 1 Through September 12,	
	2018		2017		2016		2016	
Computed at federal statutory rate	$ 47,315	21.0 %	$ 9,701	35.0 %	$ (1,854)	35.0 %	$ 369,111	35.0 %
State income taxes, net of federal income tax benefit	1,743	0.8 %	(1,383)	(5.0)%	197	(3.7)%	1,989	0.2 %
Change in valuation allowance	(48,820)	(21.7)%	(24,353)	(87.8)%	1,657	(31.3)%	(384,692)	(36.5)%
Effect of rate change on the valuation allowance	—	— %	(86,612)	(312.5)%	—	— %	—	— %
Effect of rate change	—	— %	86,612	312.5 %	—	— %	—	— %
Reorganization adjustments	—	— %	10,760	38.8 %	—	— %	13,572	1.3 %
Other, net	285	0.1 %	332	1.2 %	—	— %	20	— %
	$ 523	0.2 %	$ (4,943)	(17.8)%	$ —	— %	$ —	— %

The following table summarizes the principal components of our deferred income tax assets and liabilities as of the dates presented:

	December 31,	
	2018	2017
Deferred tax assets:		
Net operating loss (“NOL”) carryforwards	$ 163,437	$ 127,821
Property and equipment	—	37,345
Pension and postretirement benefits	441	452
Share-based compensation	546	435
Fair value of derivative instruments	—	8,752
Other	8,836	7,608
	173,260	182,413
Less: Valuation allowance	(128,650)	(177,470)
Total net deferred tax assets	44,610	4,943
Deferred tax liabilities:		
Property and equipment	33,413	—
Fair value of derivative instruments	9,248	—
Total deferred tax liabilities	42,661	—
Net deferred tax assets	$ 1,949	$ 4,943

Analysis of 2018 Tax Reform

On December 22, 2017, the U.S. Congress enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (the "TCJA"). The TCJA makes broad and complex changes to the U.S. tax code, including but not limited to, (i) the requirement to pay a one-time transition tax on all undistributed earnings of foreign subsidiaries; (ii) reducing the U.S. federal corporate income tax rate from 35% to 21%; (iii) generally eliminating U.S. federal income taxes on dividends from foreign subsidiaries; (iv) creating a new limitation on deductible interest expense; (v) changing rules related to use and limitations of NOL carryforwards created in tax years beginning after December 31, 2017 and (vi) repeal of the corporate alternative minimum tax ("AMT").

In connection with our analysis of the impact of the TCJA, we recorded income tax charge of $86.6 million for the year ended December 31, 2017, which consists of a reduction of deferred tax assets previously valued at 35%. We recorded a corresponding decrease in our deferred tax asset valuation allowance representing an income tax benefit for the same amount. The reduction in the statutory U.S. federal rate is expected to positively impact the Company's future US after tax earnings. As a result of the repeal of the AMT, our existing AMT credit carryovers became refundable beginning with the 2018 tax year. The AMT credit carryforwards are used to offset current year regular tax liabilities with 50 percent of any excess remaining credit per year being refundable as part of the annual income tax filing. We anticipate a full refund of our approximately $5 million of the AMT credit carryforwards by 2021.

Income Tax Provision

The provision for the year ended December 31, 2018 includes a current federal benefit of $2.5 million attributable to the anticipated refund of AMT credits for the 2018 tax year. This amount has been recognized as a "current income tax receivable" on our Consolidated Balance Sheet as of December 31, 2018. This benefit is offset by a corresponding decrease in the deferred tax asset associated with the refundable AMT credit giving rise to a deferred federal expense. In addition, we have a recognized a deferred state tax expense of $0.5 million for an overall effective tax rate of 0.2%. The remaining AMT credit carryforwards of approximately $2.5 million will be reclassified from deferred tax assets, where they are classified as of December 31, 2018, to current income tax receivables upon the filing of federal returns in future years.

In addition to the aforementioned offsetting items with respect to the reduction in income tax rates, our income tax provision for the year ended December 31, 2017 included federal income taxes of $9.7 million applied at the statutory rate of 35% for 2017 and an adjustment of $10.8 million attributable to reductions in certain tax attributes of property and other adjustments of $0.3 million applied in connection with the filing of our 2016 income tax returns. These expenses were effectively offset by benefits attributable to the reduction in our deferred tax asset valuation allowance of $24.4 million and state income tax benefits of $1.4 million resulting in a net tax deferred benefit of $4.9 million. The entire federal tax benefit and the corresponding net deferred tax asset presented on our Consolidated Balance Sheet as of December 31, 2017 are exclusively attributable to the AMT credit carryforwards.

Deferred Tax Assets and Liabilities

As of December 31, 2018, we had federal NOL carryforwards of approximately $557.2 million, a substantial portion of which, if not utilized, expire between 2032 and 2037. NOLs incurred after January 1, 2018 can be carried forward indefinitely. State NOL carryforwards of approximately $437.9 million expire between 2024 and 2037. Because of the change in ownership provisions of the Code, use of a portion of our federal and state NOL may be limited in future periods. As of December 31, 2018, we carried a valuation allowance against our federal and state deferred tax assets of $128.7 million. We considered both the positive and negative evidence in determining whether it was more likely than not that some portion or all of our deferred tax assets will be realized. The amount of deferred tax asset considered realizable could, however, be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as our projections for growth. Our net deferred tax assets recognized on the Consolidated Balance Sheets as of December 31, 2018 and 2017 are attributable to AMT credit carryforwards, and net of certain state deferred tax liabilities as of December 31, 2018. The valuation allowance related to all other net deferred tax assets remains in full.

Other Income Tax Matters

We had no liability for unrecognized tax benefits as of December 31, 2018 and 2017. There were no interest and penalty charges recognized during the years ended December 31, 2018, 2017 and 2016. Tax years from 2013 forward remain open for examination by the Internal Revenue Service and various state jurisdictions, and certain taxes are not dischargeable in bankruptcy.

12. Executive Retirement and Exit Activities

Executive Retirement

Effective February 28, 2018, Mr. Harry Quarls retired from his position as a director and Executive Chairman of the Company. In connection with his retirement, we entered into a separation and consulting agreement ("Separation Agreement") whereby Mr. Quarls provided transition and support services to us through December 31, 2018. We paid Mr. Quarls $0.3 million for such services. The Separation Agreement included a general release of claims and provided for the accelerated vesting of certain share-based compensation awards for which we recognized expense of $0.6 million during the year ended December 31, 2018 (see Note 17). The costs associated with the Separation Agreement, including the share-based compensation charges, are included as a component of "G&A expenses" in our Consolidated Statements of Operations.

Exit Activities

During 2016, we committed to a number of actions, or exit activities. The most significant of those activities were attributable to an overall reduction in the scope and scale of our organization and required payments to satisfy obligations associated with the underlying commitments. The following summarizes the most significant exit activities.

Reductions in Force

In 2016, we reduced our total employee headcount by 53 employees. We paid a total of $2.1 million, including $1.4 million in severance and termination benefits and $0.7 million in retention bonuses during the year ended December 31, 2016. The costs associated with these reduction-in-force and retention actions are included as a component of our "General and administrative" expenses in our Consolidated Statements of Operations.

Drilling Rig Termination

In connection with the suspension of our 2016 drilling program, we terminated a drilling rig contract and incurred $1.7 million in early termination charges. As this obligation represented a pre-petition liability of the Predecessor, it was discharged in connection with our emergence from bankruptcy and included in "Reorganization items, net" in our Consolidated Statements of Operations.

Firm Transportation Obligation

We had a contractual obligation with a carrying value of $10.8 million 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" in our Consolidated Statement of Operations. In connection with our emergence from bankruptcy, we rejected the underlying contract and the obligation was included in "Reorganization items, net" in our Consolidated Statements of Operations.

13. Additional Balance Sheet Detail

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

	December 31, 2018	December 31, 2017
Other current assets:		
Tubular inventory and well materials	$ 4,061	$ 5,146
Prepaid expenses	1,064	1,104
	$ 5,125	$ 6,250
Other assets:		
Deferred issuance costs of the Credit Facility	$ 2,437	$ 2,857
Deposit in escrow [1]	—	3,210
Other	44	2,440
	$ 2,481	$ 8,507
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 16,507	$ 22,579
Drilling costs	22,434	22,389
Royalties and revenue - related	51,212	39,287
Production, ad valorem and other taxes [2]	2,418	1,275
Compensation - related	4,489	2,975
Interest	670	223
Reserve for bankruptcy claims	—	3,933
Other [2]	5,970	3,520
	$ 103,700	$ 96,181
Other liabilities:		
Asset retirement obligations	$ 4,314	$ 3,286
Defined benefit pension obligations	857	971
Postretirement health care benefit obligations	362	476
Other	—	100
	$ 5,533	$ 4,833

[1] The December 31, 2017 amount represents amounts that had remained in the Escrow Account for the Devon Acquisition which fully funded the remaining liability due to Devon for the final settlement (see Note 5).
[2] The amount for December 31, 2017 was reclassified from Accounts payable and accrued liabilities - Other.

14. 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.

We use a hierarchy that prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below.

Fair value measurements are classified and disclosed in one of the following three categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

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 and Second Lien Facility borrowings. Due to the short-term nature of their maturities, the carrying value of our cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Our derivatives are marked-to-market and presented at their values. The carrying value of our long-term debt, which includes the Credit Facility and the Second Lien Facility, approximated their fair values as they represent variable-rate debt and their interest rates are reflective of market rates.

Recurring Fair Value Measurements

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

	December 31, 2018			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Commodity derivative assets – current	$ 34,932	$ —	$ 34,932	$ —
Commodity derivative assets – noncurrent	10,100	—	10,100	—
Liabilities:				
Commodity derivative liabilities – current	$ (991)	$ —	$ (991)	$ —
Commodity derivative liabilities – noncurrent	—	—	—	—

	December 31, 2017			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Liabilities:				
Commodity derivative liabilities – current	$ (27,777)	$ —	$ (27,777)	$ —
Commodity derivative liabilities – noncurrent	(13,900)	—	(13,900)	—

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 any period in the years ended December 31, 2018, 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 WTI and LLS crude oil 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 Consolidated Financial Statements are those attributable to the recognition and measurement of the Successor's net assets with respect to the application of Fresh Start Accounting. Those measurements are more fully described in Note 4. 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, as well as the initial determination of AROs associated with the ongoing development of new 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 Emergence Date, we apply a ceiling test determination utilizing prescribed procedures as described in Note 3. The full cost method is substantially different from the successful efforts method which relies upon fair value measurements.

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.

15. Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2018, by category, for the next five years and thereafter:

Year	Minimum Rentals	Drilling and Completion	Gathering and Intermediate Transportation	Other Commitments
2019	$ 532	$ 20,692	$ 11,702	$ 254
2020	657	—	12,962	121
2021	637	—	12,962	44
2022	638	—	12,962	—
2023	634	—	12,962	—
Thereafter	159	—	50,750	—
Total	$ 3,257	$ 20,692	$ 114,300	$ 419

Rental Commitments

Operating lease rental expense was $2.7 million, $1.0 million, $0.2 million and $2.4 million, for the years ended December 31, 2018 and 2017, the Successor period from September 13, 2016 through December 31, 2016, and the Predecessor period from January 1, 2016 through September 12, 2016, related primarily to field equipment, office equipment and office leases.

Drilling and Completion Commitments

We had a contractual commitment for one drilling rig as of December 31, 2018. Upon expiration of its original term in February 2019, the drilling rig will be converted from a fixed-term commitment to a pad-to-pad basis. We also had two other drilling rigs contracted as of December 31, 2018 on pad-to-pad terms. In December 2018, we entered into a one-year commitment, which can be terminated with 60-days' notice by either party, to utilize certain frac services, which is effective January 1, 2019.

Gathering and Intermediate Transportation Commitments

We have long-term agreements with Republic Midstream and Republic Midstream Marketing, LLC ("Republic Marketing" and, together with Republic Midstream, collectively, "Republic") to provide 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.

In August 2016, the Bankruptcy Court approved a settlement with Republic and authorized the assumption of certain amended agreements with Republic (the "Amended Agreements"). We paid Republic $0.3 million in connection with the settlement which is included in "Reorganization items, net" in our Consolidated Statements of Operations.

Under the terms of the Amended Agreements, Republic is obligated to gather and transport our crude oil and condensate from within a dedicated area in the Eagle Ford (the "Dedication Area") via a gathering system and intermediate takeaway pipeline connecting to a downstream interstate pipeline operated by a third party. The amended gathering agreement reduced our minimum volume commitment from 15,000 to 8,000 gross barrels of oil per day. The term of the amended gathering agreement runs through 2041, with the term of the minimum volume commitment extended from 10 to 15 years through 2031. The gathering portion of these minimum commitments are being recognized as a component of our gathering, processing and transportation expense while the intermediate transportation and pipeline support commitments are recognized as a reduction to the index-based price that we receive for crude oil sold to Republic in accordance with Amended Agreements.

Under the amended marketing agreement, we have a 10-year commitment to sell 8,000 barrels per day of crude oil (gross) to Republic, or any third party, utilizing Republic Marketing's capacity on a certain downstream interstate pipeline.

Other Commitments

We have entered into certain contractual arrangements for other products and services. We have purchase commitments for certain materials as well as minimum commitments under information technology licensing and service agreements, among others.

Legal

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 December 31, 2018, we had a reserve in the amount of $1.3 million included in Accounts payable and accrued liabilities for the estimated settlement of disputes with partners regarding certain transactions that occurred in prior years. A total of $1.0 million of this amount was paid in January 2019. In addition, during 2018 we eliminated a $0.1 million reserve for a litigation matter that was ultimately resolved and did not require settlement.

Environmental Compliance

Extensive federal, state and local laws govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2018, we have recorded AROs of $4.3 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws, including any significant limitation on the use of hydraulic fracturing, have the potential to adversely affect our operations.

16. Shareholders' Equity

Preferred Stock

As discussed in Note 4, all of our Predecessor preferred stock was canceled upon our emergence from bankruptcy on the Emergence Date. As of December 31, 2018 and December 31, 2017, there were 5,000,000 Successor shares of preferred stock authorized with none issued or outstanding.

Common Stock

As discussed in Note 4, all our Predecessor common stock was canceled upon our emergence from bankruptcy on the Emergence Date and 14,992,018 shares of Successor Common Stock were issued with a par value of $0.01 per share. We have a total of 45,000,000 shares authorized. We do not anticipate that cash dividends or other distributions will be paid with respect to our common stock in the foreseeable future. In addition, our Credit Facility and Second Lien Facility have restrictive covenants that limit our ability to pay dividends.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income and losses are entirely attributable to our pension and postretirement health care benefit obligations. The accumulated other comprehensive income, net of tax, was less than $0.1 million for all periods presented.

Treasury Stock

Shares of our Predecessor common stock held by the SERP and Predecessor deferred common stock units that had not been converted into Predecessor common stock were previously presented for financial reporting purposes as treasury stock carried at cost. As discussed above, all of the Predecessor common stock held by the SERP and Predecessor deferred common stock units were canceled upon our emergence from bankruptcy on the Emergence Date.

17. Share-Based Compensation and Other Benefit Plans

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

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 347,440 time-vested restricted stock units ("RSUs") and 98,526 performance restricted stock units ("PRSUs") have been granted as of December 31, 2018.

In the Predecessor period in 2016, we had outstanding equity-classified awards in the form of stock options, restricted stock units and deferred stock units. As discussed in Note 4, all Predecessor equity-classified share-based compensation awards were canceled in connection with our emergence from bankruptcy.

With the exception of our Predecessor performance-based restricted stock units ("Predecessor PBRSUs"), all of our Successor and Predecessor share-based compensation awards are classified as equity instruments because they result in the issuance of common stock on the date of grant, upon exercise or are otherwise payable in common stock upon vesting, as applicable. The compensation cost attributable to these awards has been measured at the grant date and recognized over the applicable vesting periods as a non-cash item of expense. Because the Predecessor PBRSUs were payable in cash, they were considered liability-classified awards and were included in "Accounts payable and accrued liabilities" (current portion) and "Other liabilities" (noncurrent portion) on the Consolidated Balance Sheets of the Predecessor. Compensation cost associated with the Predecessor PBRSUs was measured at the end of each reporting period and recognized based on the period of time that had elapsed during each of the individual performance periods.

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

	Successor			Predecessor
			September 13 Through	January 1 Through
	Year Ended December 31,		September 30,	September 12,
	2018	2017	2016	2016
Equity-classified awards	$ 4,618	$ 3,809	$ 81	$ 1,511
Liability-classified awards	—	—		(19)
	$ 4,618	$ 3,809	$ 81	$ 1,492

Stock Options

The exercise price of all stock options granted under our Predecessor incentive compensation plans was equal to the fair value of our common stock on the date of the grant. Options could be exercised at any time after vesting and prior to ten years following the date of grant. Options vested upon terms established by the compensation and benefits committee of our Predecessor board of directors. Generally, options vested over a three-year period, with one-third vesting in each year. In connection with our emergence from bankruptcy, all stock options outstanding as of September 12, 2016 were canceled.

Time-Vested Restricted Stock Units

A restricted stock unit entitles the grantee to receive a share of common stock upon the vesting of the restricted stock unit. The grant date fair value of our time-vested restricted stock unit awards are recognized on a straight-line basis over the applicable vesting period.

The following table summarizes activity for our most recent fiscal year with respect to awarded RSUs:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	259,990	$ 41.32
Granted	42,459	$ 65.96
Vested	(79,828)	$ 38.90
Forfeited	(14,581)	$ 43.64
Balance at end of year	208,040	$ 47.35

As of December 31, 2018, we had $7.8 million of unrecognized compensation cost attributable to RSUs. We expect that cost to be recognized over a weighted-average period of 1.5 years. The total grant-date fair values of RSUs that vested in 2018 and 2017 was $3.3 million and $0.8 million, respectively. No RSUs vested during 2016. In connection with our emergence from bankruptcy, all Predecessor RSUs outstanding as of September 12, 2016 were canceled.

Predecessor Performance-Based Restricted Stock Units

In each of the years ended December 31, 2015, 2014 and 2013, we granted Predecessor PBRSUs to certain executive officers. Vested Predecessor PBRSUs were payable solely in cash on the third anniversary of the date of grant based upon the achievement of specified market-based performance metrics with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The number of Predecessor PBRSUs vested ranged from 0% to 200% of the initial grant. The Predecessor PBRSUs did not have voting rights and did not participate in dividends. In connection with our emergence of bankruptcy, all Predecessor PBRSUs outstanding as of September 12, 2016 were canceled.

Successor Performance Restricted Stock Units

In the year ended December 31, 2017, we granted 98,526 PRSUs to members of our management. There were no PRSUs granted for the year ended December 31, 2018. The PRSUs were issued collectively in two to 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% of the original grant based on the performance of our common stock relative to an industry index. Due to their market condition, the PRSUs are being charged to expense using graded vesting over a maximum of five years. The fair value of each PRSU award was estimated on their grant dates using a Monte Carlo simulation with a range of $47.70 to $65.28 per PRSU.

The ranges for the assumptions used in the Monte Carlo model for the PRSUs granted during 2017 are presented as follows:

Expected volatility	59.63% to 62.18%
Dividend yield	0.0% to 0.0%
Risk-free interest rate	1.44% to 1.51%

The following table summarizes activity for our most recent fiscal year with respect to PRSUs:

	Performance Restricted Stock Units	Weighted-Average Fair Value
Balance at beginning of year	98,526	$ 57.81
Granted	—	$ —
Vested	(1,968)	$ 49.56
Forfeited	(7,487)	$ 49.56
Balance at end of year	89,071	$ 58.69

Defined Contribution Plan

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 provide matching contributions on our employees' elective deferral contributions up to six percent of compensation up to the maximum statutory limits. The 401(k) Plan also provides for discretionary employer contributions. The expense recognized with respect to the 401(k) Plan was $0.6 million, $0.5 million, $0.1 million and $0.5 million for the years ended December 31, 2018 and 2017, the Successor period from September 13, 2016 through December 31, 2016, and the Predecessor period from January 1, 2016 through September 12, 2016, respectively, and is included as a component of "General and administrative expenses" in our Statements of Operations. Amounts representing accrued obligations to the 401(k) Plan of $0.3 million and $0.2 million are included in the "Accounts payable and accrued expenses" caption on our Consolidated Balance Sheets as of December 31, 2018 and 2017, respectively.

Defined Benefit Pension and Postretirement Health Care Plans

We maintain unqualified legacy defined benefit pension and defined benefit postretirement health care plans which cover a limited population of former employees that retired prior to January 1, 2000. The combined expense recognized with respect to these plans was less than $0.1 million, $0.1 million, less than $0.1 million and less than $0.1 million for the years ended December 31, 2018 and 2017, the Successor period from September 13, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through September 12, 2016, respectively, and is included as a component of "General and administrative expenses" in our Statements of Operations. The combined unfunded benefit obligations under these plans were $1.4 million and are included within the "Accounts payable and accrued expenses" (current portion) and "Other liabilities" (noncurrent) captions on our Consolidated Balance Sheets as of December 31, 2018 and 2017.

18. Interest Expense

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

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through December 31,
	2018	2017	2016	2016
Interest on borrowings and related fees [1]	$ 32,164	$ 6,995	$ 678	$ 36,012
Accretion of original issue discount [2]	680	161	—	—
Amortization of debt issuance costs [3]	2,736	1,961	226	22,189
Capitalized interest	(9,118)	(2,725)	(25)	(183)
	$ 26,462	$ 6,392	$ 879	$ 58,018

[1] Absent the bankruptcy proceedings and the corresponding suspension of the accrual of interest on unsecured debt, we would have recorded total contractual interest expense of $66.1 million for the Predecessor period from January 1, 2016 through September 12, 2016, including $ 15.3 million attributable to the 2019 Senior Notes and $ 46.3 million attributable to the 2020 Senior Notes.

[2] Includes accretion of original issue discount attributable to the Second Lien Facility (see Note 10).

[3] The year ended December 31, 2017 includes a total of $0.8 million of write-offs attributable to changes in the composition of financial institutions comprising the Credit Facility's bank group in connection with amendments to the Credit Facility (see Note 10). The Predecessor period from January 1, 2016 through September 12, 2016 includes $20.5 million related to the accelerated write-off of unamortized debt issuance costs associated with the RBL and Senior Notes (see Note 10).

19. Earnings per Share

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings per share utilizing the two-class method for the periods presented:

	Successor			Predecessor
	Year Ended December 31,		September 13 Through December 31,	January 1 Through September 12,
	2018	2017	2016	2016
Net income (loss)	$ 224,785	$ 32,662	$ (5,296)	$ 1,054,602
Less: Preferred stock dividends	—	—	—	(5,972)
Net income (loss) attributable to common shareholders – basic and diluted	$ 224,785	$ 32,662	$ (5,296)	$ 1,048,630
Weighted-average shares – basic	15,059	14,996	14,992	88,013
Effect of dilutive securities [1]	233	67	—	36,074
Weighted-average shares – diluted	15,292	15,063	14,992	124,087

[1] For the period from September 13, 2016 through December 31, 2016, less than 0.1 million potentially dilutive securities, represented by RSUs, had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share.

Supplemental Quarterly Financial Information (Unaudited)

		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
2018								
Revenues [1]	$	77,211	$	111,580	$	127,185	$	124,856
Operating income	$	33,912	$	55,886	$	64,036	$	54,921
Income (loss) attributable to common shareholders [2]	$	10,295	$	(2,521)	$	16,276	$	200,735
Income (loss) per share – basic [3]	$	0.68	$	(0.17)	$	1.08	$	13.32
Income (loss) per share – diluted [3]	$	0.68	$	(0.17)	$	1.06	$	13.10
Weighted-average shares outstanding:								
Basic		15,042		15,058		15,062		15,075
Diluted		15,081		15,058		15,344		15,328

		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
2017								
Revenues [4]	$	34,986	$	36,282	$	34,459	$	54,327
Operating income	$	11,623	$	11,460	$	7,547	$	21,242
Income (loss) attributable to common shareholders	$	28,081	$	21,329	$	(5,947)	$	(10,801)
Income (loss) per share – basic [3]	$	1.87	$	1.42	$	(0.40)	$	(0.72)
Income (loss) per share – diluted [3]	$	1.86	$	1.42	$	(0.40)	$	(0.72)
Weighted-average shares outstanding:								
Basic		14,992		14,992		14,994		15,006
Diluted		15,126		15,050		14,994		15,006

[1] Includes gains (losses) on sales of assets of less than $0.1 million, less than $0.1 million, less than $0.1 million and $(0.3) million during the quarters ended March 31, 2018, June 30, 2018, September 30, 2018 and December 31, 2018, respectively.

[2] The quarter ended December 31, 2018 includes a mark-to-market gain on derivatives of $149.2 million.

[3] The sum of the quarters may not equal the total of the respective year's earnings per common share due to changes in weighted-average shares outstanding throughout the year.

[4] Includes gains (losses) on sales of assets of less than $0.1 million, $(0.1) million, less than $0.1 million and less than $0.1 million during the quarters ended March 31, 2017, June 30, 2017, September 30, 2017 and December 31, 2017, respectively.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Oil and Gas Reserves

All of our proved oil and gas reserves are located in the continental United States. The estimates of our proved oil and gas reserves were prepared by our independent third party engineers, DeGolyer and MacNaughton, Inc. utilizing data compiled by us. DeGolyer and MacNaughton, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists. Our Vice President, Engineering is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc.

Reserve engineering is a process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, NGLs and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future prices for these commodities may all differ from those assumed. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available.

The following table sets forth our estimate of net quantities of proved reserves, including changes therein and proved developed and proved undeveloped reserves for the periods presented:

Proved Developed and Undeveloped Reserves	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total Equivalents (MBOE)
December 31, 2015 (Predecessor)	29,462	7,204	42,153	43,691
Revisions of previous estimates	(1,359)	(1,225)	(8,661)	(4,028)
Extensions and discoveries	11,529	1,483	7,196	14,213
Production	(3,021)	(697)	(4,006)	(4,386)
December 31, 2016 (Successor)	36,611	6,765	36,682	49,490
Revisions of previous estimates	(5,735)	(2,071)	(10,468)	(9,550)
Extensions and discoveries	23,850	3,571	16,840	30,228
Production	(2,764)	(523)	(2,949)	(3,779)
Purchase of reserves	3,867	1,122	7,162	6,183
December 31, 2017 (Successor)	55,829	8,864	47,267	72,572
Revisions of previous estimates	(19,096)	(1,789)	(9,608)	(22,487)
Extensions and discoveries	48,119	11,737	59,447	69,764
Production	(6,077)	(1,004)	(5,181)	(7,944)
Purchase of reserves	11,278	969	5,827	13,218
Sale of reserves in place	(397)	(733)	(6,259)	(2,173)
December 31, 2018 (Successor)	89,656	18,044	91,493	122,950
Proved Developed Reserves:				
December 31, 2016	17,734	4,335	24,899	26,219
December 31, 2017	22,412	4,882	27,229	31,832
December 31, 2018	35,190	6,279	31,833	46,774
Proved Undeveloped Reserves:				
December 31, 2016	18,877	2,430	11,783	23,271
December 31, 2017	33,417	3,982	20,038	40,740
December 31, 2018	54,466	11,765	59,660	76,176

The following is a discussion and analysis of the significant changes in our proved reserve estimates for the periods presented:

Year Ended December 31, 2018

In 2018, our proved reserves increased by 50.4 MMBOE. The overall increase over our proved reserves at the end of 2017 is due primarily to a significant shift in our development plans from the northwest portion of our acreage position in the Eagle Ford to the southeast region. The performance of our wells drilled in the southeast region in the first half of the year was the impetus to our redirecting of resources and replication, to the extent practical, of our drilling and completion design techniques for the second half of 2018. Of the 53 gross wells we drilled in 2018, 19 gross wells were not proved undeveloped locations at the end of 2017. Accordingly, our five-year drilling plan is heavily weighted to the southeast region.

We had downward revisions of 22.5 MMBOE including: (i) 21.1 MMBOE due to the loss of certain locations resulting from changes in the drilling locations and timing attributable to our development plans as discussed above and (ii) 4.4 MMBOE due to well performance partially offset by (iii) 1.2 MMBOE due to improved treatable lateral lengths in certain locations due primarily to reconfiguration of the planned drilling units and (iv) 1.8 MMBOE of other changes, primarily price-related. Extensions and discoveries of 69.8 MMBOE are substantially attributable to geographical shift in our development plan, greater utilization of extended reach laterals, increasing the length of such laterals, higher EUR estimates per lateral foot and higher net revenue interests due to the Hunt Acquisition. We acquired 13.2 MMBOE in connection with the Hunt Acquisition and we sold 2.2 MMBOE in connection with our exit from the Mid-Continent region.

Year Ended December 31, 2017

We had downward revisions of 9.6 MMBOE as a result of the following: (i) downward revisions of 6.5 MMBOE due primarily to reduced treatable lateral lengths in certain locations due primarily to reconfiguration of the planned drilling units partially offset by improved performance, (ii) downward revisions of 4.7 MMBOE to our proved undeveloped reserves due to the loss of certain locations resulting from changes in the timing and drilling locations attributable to our development plans partially offset by (iii) 1.6 MMBOE due to improved well performance. Extensions and discoveries of 30.2 MMBOE are entirely attributable to our expanded development plan including adding a third rig to our drilling program and the corresponding increase in the number of drilling locations that we are planning to drill in the next five years. We acquired 6.2 MMBOE in connection with the Devon Acquisition. An additional 1.0 MMBOE attributable to the Devon Acquisition was determined in our year-end assessment consistent with our development plans and is included in the aforementioned extensions and discoveries.

Year Ended December 31, 2016

We had downward revisions of 4.0 MMBOE primarily as a result of the following: (i) revisions of 1.7 MMBOE due to lower EURs for natural gas and NGLs net of higher expected crude oil recoveries attributable to our existing and new Eagle Ford wells, (ii) revisions of 1.3 MMBOE to our proved undeveloped reserves due to the loss of certain locations resulting from changes in the timing of our development plans and lower EURs, (iii) revisions of 0.7 MMBOE (Granite Wash - 0.4 MMBOE and Eagle Ford 0.3 MMBOE) due to lower commodity prices compared to year-end 2015 and (iv) revisions of 0.3 MMBOE to our Granite Wash wells due to well performance. Extensions and discoveries of 14.2 MMBOE for our proved undeveloped reserves were attributable to the resumption of our development plans.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth capitalized costs related to our oil and gas producing activities and accumulated DD&A for the periods presented:

	December 31,		
	2018	2017	2016
Oil and gas properties:			
Proved	$ 1,037,993	$ 460,029	$ 251,083
Unproved	63,484	117,634	4,719
Total oil and gas properties	1,101,477	577,663	255,802
Other property and equipment	16,462	10,057	1,230
Total capitalized costs relating to oil and gas producing activities	1,117,939	587,720	257,032
Accumulated depreciation and depletion	(191,802)	(60,247)	(11,669)
Net capitalized costs relating to oil and gas producing activities [1]	$ 926,137	$ 527,473	$ 245,363

[1] Excludes property and equipment attributable to our corporate operations which is comprised of certain capitalized hardware, software, leasehold improvements and office furniture and fixtures.

Costs Incurred in Certain Oil and Gas Activities

The following table summarizes costs incurred in our oil and gas property acquisition, exploration and development activities for the periods presented:

	Successor			Predecessor
			September 13 Through December 31,	January 1 Through September 12,
	Year Ended December 31,			
	2018	2017	2016	2016
Development costs [1]	$ 416,037	$ 135,360	$ 5,399	$ 4,777
Proved property acquisition costs [2]	86,514	43,151	53	—
Unproved property acquisition costs [3]	30,637	153,905	25	183
Exploration costs [4]	377	696	567	8,311
	$ 533,565	$ 333,112	$ 6,044	$ 13,271

[1] Includes plugging and abandonment asset additions for all periods presented and capitalized internal costs for the Successor periods during which time we have applied the full cost method of accounting for oil and gas properties.

[2] Includes proved properties and plugging and abandonment assets acquired in the Hunt and Devon Acquisitions during the years ended December 31, 2018 and 2017.

[3] Includes capitalized interest for all periods presented and unproved properties acquired in the Hunt and Devon Acquisitions during the years ended December 31, 2018 and 2017.

[4] Includes geological costs, geophysical costs (seismic) and delay rentals for all periods presented. Also includes: (i) drilling rig termination charges of $1.7 million, (ii) a $2.0 million charge for failure to complete a drilling carry commitment, (iii) a $0.6 million charge for unutilized coiled tubing services and (iv) a $4.0 million write-off of certain uncompleted well costs during the Predecessor period ended September 12, 2016, all of which were charged to exploration expense during which time we applied the successful efforts method of accounting for oil and gas properties.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Future cash inflows were computed by applying the average prices of oil and gas during the 12-month period prior to the period end, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated costs as of that fiscal year end, to the estimated future production of proved reserves. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available NOL carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

The standardized measure of discounted future net cash flows is not intended, and should not be interpreted, to represent the fair value of our oil and gas reserves. An estimate of the fair value would also consider, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and cost, and a discount factor more representative of economic conditions and risks inherent in reserve estimates. Accordingly, the changes in standardized measure reflected above do not necessarily represent the economic reality of such transactions.

Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu with the representative price of natural gas adjusted for basis premium and energy content to arrive at the appropriate net price. NGL prices were estimated as a percentage of the base crude oil price.

The following table summarizes the price measurements utilized, by product, with respect to our estimates of proved reserves as well as in the determination of the standardized measure of the discounted future net cash flows for the periods presented:

	Crude Oil	NGLs	Natural Gas
	$ per Bbl	$ per Bbl	$ per MMBtu
As of December 31, 2016	$ 42.75	$ 12.33	$ 2.48
As of December 31, 2017	$ 51.34	$ 18.48	$ 2.98
As of December 31, 2018	$ 65.56	$ 23.60	$ 3.10

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	December 31,		
	2018	2017	2016
Future cash inflows	$ 6,719,145	$ 3,091,366	$ 1,667,971
Future production costs	(1,852,168)	(1,069,910)	(673,538)
Future development costs	(1,208,815)	(689,998)	(327,213)
Future net cash flows before income tax	3,658,162	1,331,458	667,220
Future income tax expense	(413,137)	(84,350)	—
Future net cash flows	3,245,025	1,247,108	667,220
10% annual discount for estimated timing of cash flows	(1,621,135)	(656,624)	(349,670)
Standardized measure of discounted future net cash flows	$ 1,623,890	$ 590,484	$ 317,550

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table summarizes the changes in the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	Year Ended December 31,		
	2018	2017	2016
Sales of oil and gas, net of production costs	$ (361,478)	$ (118,137)	$ (89,080)
Net changes in prices and production costs	585,737	170,488	(11,971)
Changes in future development costs	206,901	30,692	59,266
Extensions and discoveries	809,880	131,060	35,321
Development costs incurred during the period	204,160	74,880	6,775
Revisions of previous quantity estimates	(483,091)	(122,357)	(38,151)
Purchases of reserves-in-place	86,128	80,878	—
Sale of reserves-in-place	(8,912)	—	—
Changes in production rates and all other	60,160	12,161	(252)
Accretion of discount	60,897	31,755	32,331
Net change in income taxes	(126,976)	(18,486)	—
Net increase (decrease)	1,033,406	272,934	(5,761)
Beginning of year	590,484	317,550	323,311
End of year	$ 1,623,890	$ 590,484	$ 317,550

Item 9 Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A Controls and Procedures

(a) Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2018. 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 within the time periods specified in the Securities and Exchange Commission's rules and forms, and that such information is accumulated and communicated to the issuer's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2018, such disclosure controls and procedures were effective.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018. This evaluation was completed based on the framework established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on that assessment, our management has concluded that, as of December 31, 2018, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

Grant Thornton LLP, the independent registered public accounting firm that audited and reported on the consolidated financial statements contained in this Form 10-K, has issued an attestation report on the internal control over financial reporting as of December 31, 2018, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B Other Information

None.

Part III

Item 10 Directors, Executive Officers and Corporate Governance

Information relating to this item will be included in an amendment to this report and is incorporated by reference in this report.

We have adopted a Code of Business Conduct and Ethics that applies to all of our directors, officer and employees, including our principal executive, principal financial and principal accounting officers, or persons performing similar functions. Our Code of Business Conduct and Ethics is posted on our website located at https://ir.pennvirginia.com/governance-docs. We intend to disclose future amendments to certain provisions of the Code of Business Conduct and Ethics, and waivers of the Code of Business Conduct and Ethics granted to executive officers and directors, on the website within four business days following the date of the amendment or waiver.

Item 11 Executive Compensation

Information relating to this item will be included in an amendment to this report and is incorporated by reference in this report.

Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information relating to this item will be included in an amendment to this report and is incorporated by reference in this report.

Item 13 Certain Relationships and Related Transactions, and Director Independence

Information relating to this item will be included in an amendment to this report and is incorporated by reference in this report.

Item 14 Principal Accountant Fees and Services

Information relating to this item will be included in an amendment to this report and is incorporated by reference in this report.

Part IV

Item 15 Exhibits and Financial Statement Schedules

The following documents are included as exhibits to this Annual Report on Form 10-K. Those exhibits incorporated by reference are indicated as such in the parenthetical following the description. All other exhibits are included herewith.

(1)	Financial Statements — The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 65 of this Annual Report on Form 10-K.
(2.1)	Second Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and Its Debtor Affiliates (Technical Modifications) filed pursuant to Chapter 11 of the United States Bankruptcy Code filed on August 10, 2016 with the United States Bankruptcy Court for the Eastern Division of Virginia, Richmond Division (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on August 17, 2016).
(2.2)	Disclosure Statement for the First Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and Its Debtor Affiliates and Amended Exhibits Thereto filed pursuant to Chapter 11 of the United States Bankruptcy Code filed on June 24, 2016 with the United States Bankruptcy Court for the Eastern Division of Virginia, Richmond Division (incorporated by reference to Exhibit 2.2 to Registrant's Current Report on Form 8-K filed on August 17, 2016).
(2.3)	Agreement and Plan of Merger dated as of October 28, 2018, by and among Denbury Resources Inc, Dragon Merger Sub Inc, DR Sub LLC Sub and Penn Virginia Corporation (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on October 29, 2018).
(3.1)	Second Amended and Restated Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on September 15, 2016).
(3.2)	Third Amended and Restated Bylaws of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registran t's Current Report on Form 8-K filed on January 19, 2018).
(10.1)	Credit Agreement, dated as of September 12, 2016, by and 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 to Registrant's Current Report on Form 8-K filed on September 15, 2016).
(10.1.1)	Amendment No. 1 to Credit Agreement dated as of March 10, 2017 among Penn Virginia Holding Corp., Penn Virginia Corporation, the guarantors and 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).
(10.1.2)	Master Assignment, Agreement and Amendment No. 2 to Credit Agreement dated as of June 27, 2017 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders and New Lenders party thereto and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 30, 2017).
(10.1.3)	Master Assignment, Agreement and Amendment No. 3 to Credit Agreement dated as of September 29, 2017 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 5, 2017).
(10.1.4)	Master Assignment, Agreement and Amendment No. 4 to Credit Agreement, dated as of March 1, 2018, among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 7, 2018).
(10.1.5)	Borrowing Base Increase Agreement and Amendment No. 5 to Credit Agreement dated as of October 26, 2018 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 26, 2018).
(10.2)	Pledge and Security Agreement, dated as of September 12, 2016, by Penn Virginia Holding Corp., Penn Virginia Corporation and the other grantors party thereto in favor of Wells Fargo Bank, National Association, as administrative agent for the benefit of the secured parties thereunder (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on September 15, 2016).
(10.3)	Registration Rights Agreement, dated as of September 12, 2016 between Penn Virginia Corporation and the holders party thereto (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on September 15, 2016).
(10.4)	Credit Agreement, dated as of September 29, 2017, by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, the lenders party thereto and Jefferies Finance LLC, as administrative agent, collateral agent and sole lead arranger (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 5, 2017).
(10.5)	Pledge and Security Agreement, dated as of September 29, 2017, by Penn Virginia Holding Corp., Penn Virginia Corporation and the other grantors party thereto in favor of Jefferies Finance LLC, as administrative agent and collateral agent for the ratable benefit of the secured parties thereunder (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on October 5, 2017).

(10.6)	Intercreditor Agreement, dated as of September 29, 2017, by and among Penn Virginia Holding Corp., Penn Virginia Corporation, the subsidiaries of Penn Virginia Holding Corp. party thereto, Wells Fargo Bank, National Association and Jefferies Finance LLC (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on October 5, 2017).
(10.7)	Purchase and Sale Agreement by and between Devon Energy Production Company, L.P. as seller, and Penn Virginia Oil & Gas, L.P. as buyer dated as of July 29, 2017 (incorporated by reference to Exhibit 10.5 to Registrant's Quarterly Report on Form 10-Q filed on November 9, 2017).
(10.8)	Purchase and Sale Agreement by and between Hunt Oil Company and Penn Virginia Oil and Gas, L.P. dated December 30, 2017 (incorporated by reference to Exhibit 10.8 to Registrant's Annual Report on Form 10-K filed on March 2, 2018).
(10.9)	Second Amended and Restated Construction and Field Gathering Agreement by and between Republic Midstream, LLC and Penn Virginia Oil & Gas, L.P. dated August 1, 2016 (incorporated by reference to Exhibit 10.5 to Registrant's Quarterly Report on Form 10-Q/A filed on November 28, 2016).
(10.9.1)	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 Registrant's Registration Statement on Form S-3/A (Amendment No. 2) filed on May 2, 2017).
(10.9.2)	Second Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of July 2, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.9.3) #	Third Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of December 14, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P.
(10.10)	First Amended and Restated Crude Oil Marketing Agreement dated as of August 1, 2016, by and between Penn Virginia Oil & Gas, L.P., Republic Midstream Marketing, LLC and solely for purposes of Article V therein, Penn Virginia Corporation (incorporated by reference to Exhibit 10.6 to Registrant's Quarterly Report on Form 10-Q/A filed on November 28, 2016).
(10.10.1) †	First Amendment to First Amended and Restated Crude Oil Marketing Agreement dated as of July 2, 2018 by and between Penn Virginia Oil & Gas, L.P. and Republic Midstream Marketing, LLC.(incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.11)*	Penn Virginia Corporation 2016 Management Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant 's Current Report on Form 8-K filed on October 11, 2016).
(10.11.1)*	Form of Nonqualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 11, 2016).
(10.11.2)*	Form of Officer Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.1 to Registrant 's Current Report on Form 8-K filed on January 30, 2017).
(10.11.3)*	Form of Performance Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 to Registrant 's Current Report on Form 8-K filed on January 30, 2017).
(10.11.4)*	Form of Director Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.1 to Registrant 's Current Report on Form 8-K filed on December 21, 2016).
(10.12)*	Separation and Consulting Agreement dated January 18, 2018 by and among Penn Virginia Corporation and Harry Quarls (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on January 19, 2018).
(10.13)*	Penn Virginia Corporation 2017 Special Severance Plan Amended and Restated Effective July 18, 2018 (incorporated by reference to Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.14)	Support Agreement, dated January 18, 2018 by and among Penn Virginia Corporation, Strategic Value Partners, LLC and certain funds and accounts managed by Strategic Value Partners, LLC (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on January 19, 2018).
(10.15)	Form of Director Indemnification Agreement (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on October 11, 2016).
(21.1) #	Subsidiaries of Penn Virginia Corporation.
(23.1) #	Consent of Grant Thornton LLP.
(23.2) #	Consent of DeGolyer and MacNaughton.
(31.1) #	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2) #	Certification Pursuant to 18 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.
(99.1) #	Report of DeGolyer and MacNaughton dated January 28, 2019 concerning evaluation of oil and gas reserves.

(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

---

* Management contract or compensatory plan or arrangement.

\# Filed herewith.

† Confidential treatment has been requested for this exhibit and confidential portions have been filed separately with the Securities and Exchange Commission.

†† Furnished herewith.

Item 16 Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENN VIRGINIA CORPORATION

By: /s/ STEVEN A. HARTMAN
Steven A. Hartman
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

February 27, 2019

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ JOHN A. BROOKS **John A. Brooks**	Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2019
/s/ STEVEN A. HARTMAN **Steven A. Hartman**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2019
/s/ TAMMY L. HINKLE **Tammy L. Hinkle**	Vice President and Controller (Principal Accounting Officer)	February 27, 2109
/s/ DAVID GEENBERG **David Geenberg**	Co-Chairman of the Board	February 27, 2109
/s/ MICHAEL HANNAH **Michael Hannah**	Director	February 27, 2109
/s/ DARIN G. HOLDERNESS **Darin G. Holderness**	Co-Chairman of the Board	February 27, 2019
/s/ VICTOR F. POTTOW **Victor F. Pottow**	Director	February 27, 2019
/s/ JERRY R. SCHUYLER **Jerry R. Schuyler**	Director	February 27, 2019

THIRD AMENDMENT TO SECOND AMENDED AND RESTATED CONSTRUCTION AND FIELD GATHERING AGREEMENT

This Third Amendment to Second Amended and Restated Construction and Field Gathering Agreement (this "***Amendment***") is dated as of December 14, 2018 (the " ***Execution Date***") by and between Republic Midstream, LLC, a Delaware limited liability company ("***Gatherer***"), and Penn Virginia Oil & Gas, L.P., a Texas limited partnership ("***Shipper***"). Gatherer and Shipper may hereinafter be referred to singularly as a "***Party***" and, together, as the " ***Parties***."

WHEREAS, the Parties entered into that certain Second Amended and Restated Construction and Field Gathering Agreement effective as of August 1, 2016 (as amended, the "***Agreement***");

WHEREAS, the Parties entered into that First Amendment to Second Amended and Restated Construction and Field Gathering Agreement, dated as of April 13, 2017;

WHEREAS, the Parties entered into that Second Amendment to Second Amended and Restated Construction and Field Gathering Agreement, dated as of July 2, 2018; and

WHEREAS, the Parties desire to amend certain provisions of the Agreement;

NOW, THEREFORE, in consideration of the mutual covenants, terms and conditions herein contained, together with other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby, the Parties, for themselves and for their successors and assigns, do hereby mutually covenant and agree as follows:

A. **Amendment of Definitions in Agreement.** Article I of the Agreement is hereby amended by adding the following definitions in appropriate alphabetical order:

"***Deedra Unit***" means that certain 482.359 acre unit described in that certain Designation of Unit recorded in Volume 672 and Page 432, Official Records of Lavaca County, Texas, as amended by that certain First Amendment to Designation of Unit recorded in Volume 691 and Page 18, Official Records of Lavaca County, Texas, and as amended by that certain Second Amendment to Designation of Unit recorded in Volume 781 and Page 294, Official Records of Lavaca County, Texas, solely to the extent not included in the area identified on the map attached hereto as Exhibit A-1. For the avoidance of doubt, the portion of the Deedra Unit within the area identified on the map attached hereto as Exhibit A-1 constitutes an Interest and part of the Dedication Area and remains subject to the dedication set forth in Article II and to the other provisions of this Agreement.

"***Future Interests***" means all interests that Shipper (or any of its Affiliates or any successor in interest resulting from any merger, reorganization, consolidation or as part of a sale or other disposition of all or any portion of such interests) now or hereinafter owns, controls, acquires or has the right to market (as such marketing rights may change from time to time) in Crude Oil reserves of, and production from, all leases and mineral fee interests, lands and formations (in each case) in, under or attributable to the Future Units, together with any pool, communitized area or unit, and all interests in any wells, whether now existing or drilled hereafter, on or completed within the Future Units, or within any such pool, communitized area or unit, even though such interests may be incorrectly or incompletely stated, all as the same shall be enlarged by the discharge of any burdens or by the removal of any charges or encumbrances to which any of same maybe subject as of (x) with respect to the Carol Unit, Robin Unit, Marcia Unit and Shelly Unit, July 2, 2018, and (y) with respect to the Deedra Unit, Nancy Unit and Lori Unit, December 14, 2018, and any and all replacements, renewals and extensions or amendments of any of the same; *provided*, *however*, that "Future Interests" shall not include (a) any Interests or (b) any interest of Shipper or any of its Affiliates that must be offered to a third-party working interest partner pursuant to any applicable agreement with such partner in effect on (1) with respect to the Carol Unit, Robin Unit, Marcia Unit and Shelly Unit, July 2, 2018, and (2) with respect to the Deedra Unit, Nancy Unit and Lori Unit, December 14, 2018, and which such partner receives or elects to receive, as applicable under the affected agreement.

"***Future Units***" means the Deedra Unit, Nancy Unit, Lori Unit, Carol Unit, Robin Unit, Marcia Unit and Shelly Unit, collectively.

"***Future Wells***" means (a) with respect to the Carol Unit, Robin Unit, Marcia Unit and Shelly Unit, any new wells drilled within the surface outline of such Future Units, and (b) with respect to the Deedra Unit, Nancy Unit and Lori Unit, the entirety of any new wells with a surface location within the surface outline of such Future Units. For the avoidance of doubt, the term "Future Wells" does not include the Other Wells.

"***Lori Unit***" means that certain 670.71 acre unit described in that certain Designation of Unit recorded in Volume 670 and Page 173, Official Records of Lavaca County, Texas, as amended by that certain Second Amendment to Designation of Unit recorded in Volume 781 and Page 306, Official Records of Lavaca County, Texas.

"***Nancy Unit***" means that certain 693.52 acre unit described in that certain Designation of Unit recorded in Volume 671 and Page 471, Official Records of Lavaca County, Texas, solely to the extent not included in the area identified on the map attached hereto as Exhibit A-1. For the avoidance of doubt, the portion of the Nancy Unit within the area identified on the map attached hereto as Exhibit A-1 constitutes an Interest and part of the Dedication Area and remains subject to the dedication set forth in Article II and to the other provisions of this Agreement.

B. **Waiver of Construction Notice.**

(1) For purposes of this Amendment, "***Deedra-Lori Initial Wells***" means the Deedra-Lori Unit 3 (SA) Well 3H and the Deedra-Lori Unit 4 (SA) Well 4H.

(2) Gatherer hereby waives the obligation set forth in Section 3.3(g) of the Agreement for Shipper to deliver a Construction Notice for the Deedra-Lori Initial Wells, and hereby agrees and elects to install an Additional Segment to connect a Receipt Point for such Future Wells. Within 30 days after the date hereof, Gatherer shall deliver to Shipper a Construction Plan in accordance with Section 3.3(b) of the Agreement. The Parties acknowledge and agree that the "Expected Production Date" with respect to the Deedra-Lori Initial Wells is March 11, 2019.

C. **Amendment of Section 9.4 of Agreement** . Section 9.4 of the Agreement is hereby amended and restated to read in its entirety as follows:

> During the first thirty-six (36) Months of the Term, the aggregate Monthly Fees shall be subject to increase by $0.04 per Barrel for every $1.00 that the Monthly average of the NYMEX West Texas Intermediate ("***WTI***") crude price exceeds $50.00 per Barrel, with such increase being capped at a WTI crude price of $90.00. After the first thirty-six (36) Months of the Term and for the remainder of the Term, the aggregate Monthly Fees shall similarly be subject to increase by $0.04 per Barrel for every $1.00 that the Monthly average WTI crude price exceeds $63.75 per Barrel, with such increase being capped at a WTI crude price of $90.00. The above-described increases shall be offset by downward adjustments to reflect corresponding decreases to the WTI crude price from time to time, provided that no downward adjustment shall be recognized for decreases below a WTI crude price of (1) $50.00 during the first thirty-six (36) Months of the Term, and (2) $63.75 after the first thirty-six (36) Months of the Term. Each of the foregoing increases or decreases shall be applied on a Monthly basis, and calculated based on the Monthly average of the WTI crude price over the preceding Month. The adjustments set forth in this Section 9.4 shall be referred to herein as the "***Upside Adjustments***". For the avoidance of doubt, no Upside Adjustment shall result in a Fee being decreased below the amount for such Fee set forth in Section 9.2, after giving effect to any PPI Adjustment. Notwithstanding the foregoing, for any month in which Shipper delivers an average of 20,000 or more Barrels of Oil per Day, the Upside Adjustment to the Truck Loading Fee shall be waived for all Oil delivered to the Gathering System from Shipper's wells outside the Dedication Area.

D. **Ratification; Primacy**. Except as expressly amended by this Amendment, all of the terms, provisions, covenants and conditions contained in the Agreement remain in full force and effect; *provided*, if there is ever any conflict between the Agreement and this Amendment, the terms, provisions, covenants and conditions contained in this Amendment shall govern. The terms and provisions of the Agreement as amended by this Amendment are binding upon and inure to the benefit of the Parties, their representatives, successors and assigns. As amended by this Amendment, the Agreement is ratified and confirmed by the Parties, and declared to be a valid and enforceable contract between them.

E. **Counterparts**. This Amendment may be executed in as many counterparts as deemed necessary. When so executed, the aggregate counterparts shall constitute one agreement and shall have the same effect as if all Parties signing counterparts had executed the same instrument.

F. **Amendment; Waiver**. Neither this Amendment nor the Agreement may be amended or modified except pursuant to a written instrument signed by all of the Parties. Each Party may waive on its own behalf compliance by any other Party with any term or provision hereof; *provided*, *however*, that any such waiver shall be in writing and shall not bind the non-waiving Party. The waiver by any Party of a breach of any term or provision shall not be construed as a waiver of any subsequent breach of the same or any other provision.

G. **Joint Preparation**. The Parties agree and confirm that this Amendment was prepared jointly by all Parties and not by any one Party to the exclusion of the other.

H. **No Third Party Beneficiaries**. This Amendment is not intended to confer upon any person not a party hereto any rights or remedies hereunder, and no person other than the Parties is entitled to rely on or enforce any provision hereof.

I. **Miscellaneous Provisions**. The provisions of Articles XVII, XIX, XX and XXI of the Agreement are incorporated herein by this reference as if set out fully herein and shall apply in all respects to this Amendment.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the Parties have executed this Amendment as of the day and year hereinabove first written.

REPUBLIC MIDSTREAM, LLC

By: /s/ Daniel R. Revers

Name: Daniel R. Revers

Title: President

PENN VIRGINIA OIL & GAS, L.P.

By: Penn Virginia Oil & Gas GP LLC, its general partner

By: /s/ Jill T. Zivley

Name: Jill T. Zivley

Title: Vice President, Land and Marketing

Exhibit 21.1

Subsidiaries of Penn Virginia Corporation

Name	Jurisdiction of Organization
Penn Virginia Holding Corp.	Delaware
Penn Virginia Oil & Gas Corporation	Virginia
Penn Virginia Oil & Gas, L.P.	Texas
Penn Virginia Oil & Gas GP LLC	Delaware
Penn Virginia Oil & Gas LP LLC	Delaware
Penn Virginia MC Corporation	Delaware
Penn Virginia MC Energy L.L.C.	Delaware
Penn Virginia MC Operating Company L.L.C	Delaware
Penn Virginia MC Gathering Company L.L.C.	Oklahoma
Penn Virginia Resource Holdings Corp.	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 27, 2019, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Penn Virginia Corporation on Form 10-K for the year ended December 31, 2018. We consent to the incorporation by reference of said reports in the Registration Statements of Penn Virginia Corporation on Form S-3 (File Nos. 333-214709 and 333-216756) and on Form S-8 (File No. 333-213979) and the Registration Statement of Denbury Resources Inc. on Form S-4 (File No. 333-228935).

/s/ GRANT THORNTON LLP

Houston, Texas
February 27, 2019

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 26, 2019

Penn Virginia Corporation
16285 Park Ten Place
Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our report entitled “Report as of December 31, 2018 on Reserves and Revenue of Certain Properties with interests attributable to Penn Virginia Corporation” (our Report) in Part I and in the “Notes to Consolidated Financial Statements” portion of the Annual Report on Form 10-K of Penn Virginia Corporation for the year ended December 31, 2018 (the Annual Report), to be filed with the United States Securities and Exchange Commission on or about February 27, 2019. In addition, we hereby consent to the incorporation by reference of our report of third-party dated January 28, 2019, in the “Exhibits and Financial Statement Schedules” portion of the Annual Report. We further consent to the incorporation by reference of references to DeGolyer and MacNaughton and to our Report in Penn Virginia Corporation’s Registration Statements on Form S-3 (File Nos. 333-214709 and 333-216756) and Form S-8 (File No. 333-213979) and Denbury Resources Inc.’s Registration Statement on Form S-4 (File No. 333-228935).

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

Exhibit 31.1

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

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

1. I have reviewed this Annual Report on Form 10-K 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: February 27, 2019

/s/ JOHN A. BROOKS

John A. Brooks
Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

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

1. I have reviewed this Annual Report on Form 10-K 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: February 27, 2019

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial Officer

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 Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John A. Brooks, Chief 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: February 27, 2019

/s/ JOHN A. BROOKS

John A. Brooks
Chief 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 Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Steven A. Hartman, Senior Vice President and Chief Financial 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: February 27, 2019

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial 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 99.1

DeGolyer and MacNaughton

5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

January 28, 2019

Penn Virginia Corporation
16285 Park Ten Place
Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2018, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Penn Virginia Corporation (Penn Virginia) has represented it holds an interest. This evaluation was completed on January 28, 2019. The properties evaluated herein consist of working and royalty interests located in Texas. Penn Virginia has represented that these properties account for 100 percent on a net oil equivalent basis of Penn Virginia's net proved reserves as of December 31, 2018. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Penn Virginia.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2018. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Penn Virginia after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Penn Virginia to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Penn Virginia, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary nominal discount rate of 10 percent compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Penn Virginia and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Penn Virginia with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Penn Virginia, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

Penn Virginia has represented that its senior management is committed to the development plan provided by Penn Virginia and that Penn Virginia has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

A performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for the evaluation of all reserves categories. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on the availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. Analysis was performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the impact of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs. The methodology used for the analysis was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, production history, and appropriate reserves definitions.

In the evaluation of non-producing and undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Penn Virginia from wells drilled through December 31, 2018, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through November 2018. Estimated cumulative production, as of December 31, 2018, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 1 month. All proved developed reserves estimated herein are considered to be proved developed producing.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include C_{5+} and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions. NGL reserves are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in barrels (bbl) representing 42 United States gallons per barrel. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel use and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. All gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Gas reserves included in this report are expressed in thousands of cubic feet (Mcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Penn Virginia, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Penn Virginia.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Penn Virginia. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Penn Virginia has represented that the oil, condensate, and NGL prices were based on West Texas Intermediate (WTI) pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Penn Virginia to the reference price of $65.56 per barrel and held constant thereafter. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $66.72 per barrel of oil and condensate and $24.99 per barrel of NGL.

Gas Prices

Penn Virginia has represented that the gas prices were based on Henry Hub pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The gas prices were calculated for each property using differentials furnished by Penn Virginia to the reference price of $3.10 per million British thermal units ($/MMBtu) and held constant thereafter. British thermal unit factors provided by Penn Virginia were used to convert prices from $/MMBtu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $3.132 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for Texas, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Penn Virginia based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Penn Virginia and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2018 values, provided by Penn Virginia, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Penn Virginia for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of non-producing and undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas of the properties evaluated by us contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2018, of the properties evaluated herein were based on the definitions of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2018			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed Producing	35,190	6,279	31,833	46,775
Proved Developed Non-Producing	0	0	0	0
Total Proved Developed	**35,190**	**6,279**	**31,833**	**46,775**
Proved Undeveloped	54,466	11,765	59,661	76,174
Total Proved	**89,656**	**18,044**	**91,494**	**122,950**

Note: Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue to be derived from the production of the net proved reserves, as of December 31, 2018, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed Producing (M$)	**Proved Developed Non-Producing (M$)**	**Total Proved Developed (M$)**	**Proved Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	2,619,165	0	2,619,165	4,099,980	6,719,145
Production and Ad Valorem Taxes	168,253	0	168,253	264,432	432,685
Operating Expenses	684,110	0	684,110	735,373	1,419,483
Capital and Abandonment Costs	24,015	0	24,015	1,184,800	1,208,815
Future Net Revenue	1,742,787	0	1,742,787	1,915,375	3,658,162
Present Worth at 10 Percent	1,027,564	0	1,027,564	741,788	1,769,352

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2018, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Penn Virginia. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Penn Virginia. DeGolyer and MacNaughton has used all data, assumptions, procedures, and methods that it considers necessary to prepare this report.

Submitted,

DeGOLYER and MacNAUGHTON Texas Registered Engineering Firm F-716

Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Penn Virginia dated
2. January 28, 2019, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.
3. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 34 years of experience in oil and gas reservoir studies and reserves evaluations.

Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton