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, 2017

or

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

For the transition period from ____ to ____

Commission file number: 1-13283

PENN VIRGINIA CORPORATION

PENN VIRGINIA CORPORATION

(Exact name of registrant as specified in its charter)

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

14701 St. Mary's Lane, Suite 275
Houston, TX 77079
(Address of principal executive offices)
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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ 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 $476,690,130 as of June 30, 2017 (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. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and executive officers of the registrant. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

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 23, 2018, 15,042,764 shares of common stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to the registrant's Annual Meeting of Shareholders, to be held on May 2, 2018, are incorporated by reference in Part III of this Form 10-K.

PENN VIRGINIA CORPORATION
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2017

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:

- risks related to recently completed acquisitions, including our ability to realize their expected benefits;
- our ability to satisfy our short-term and long-term liquidity needs, including our inability to generate sufficient cash flows from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs;
- negative events or publicity adversely affecting our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties;
- 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 natural gas reserves and sustain production;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, NGLs and natural gas;
- our ability to contract for drilling rigs, frac crews, supplies and services at reasonable costs;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell our production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from that estimated in our proved oil and natural gas reserves;
- drilling and operating risks;
- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- potential adverse effects of the completed Chapter 11, or bankruptcy, proceedings on our liquidity, results of operations, business prospects, ability to retain financing and other risks and uncertainties related to our emergence from bankruptcy;
- our post-bankruptcy capital structure and the adoption of Fresh Start Accounting (as defined herein), including the risk that assumptions and factors used in estimating enterprise value vary significantly from the current estimates in connection with the application of Fresh Start Accounting;
- counterparty risk related to the ability of these parties to meet their future obligations;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties relating to general domestic and international economic and political conditions;
- the impact and costs associated with litigation or other legal matters; and
- other factors set forth in our periodic filings with the Securities and Exchange Commission, 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, 2017.

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 field, or the Eagle Ford, in South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash.

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 an 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. Each of our operating regions has similar economic characteristics and meets the criteria for aggregation as one reporting segment.

Current Operations

We lease a highly contiguous position of approximately 73,400 net acres (as of December 31, 2017) 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 2017, our total production was comprised of 73 percent crude oil, 14 percent NGLs and 13 percent natural gas. Crude oil accounted for 88 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, 2017, our total proved reserves were approximately 73 MMBOE, of which44 percent were proved developed reserves and 77 percent were crude oil. Approximately 97 percent of our reserves were located in South Texas and 42 percent were proved developed reserves. As of December 31, 2017, we had 500 gross (332.9 net) productive wells, approximately 80 percent of which we operate, and owned approximately 124,000 gross (90,000 net) acres of leasehold and royalty interests, approximately 18 percent of which were undeveloped. Over 90 percent of our undeveloped acreage in South Texas is HBP and includes a substantial number of undrilled locations. During 2017, we drilled and completed 29 gross (16.9 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.”

In September 2017, we completed an acquisition of oil and gas assets, including oil and gas leases covering approximately 19,600 net acres located primarily in Lavaca County, Texas from Devon Energy Corporation, or Devon. 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. With such acquisitions, we have an approximate 83,100 core net acreage position in South Texas with approximately 93 percent HBP, substantially all of which is operated by us. For a more detailed discussion of these acquisitions, 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 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.”

Business Strategy

Our goal is to enhance long-term shareholder value. We intend to pursue the following business strategies:

- *Grow reserves, production and cash flow by exploiting our liquids rich resource base*. We believe our extensive inventory of drilling locations in the Eagle Ford, combined with our operating expertise, will enable us to continue to deliver accretive production, reserves and cash flow growth and create shareholder value. We intend to selectively develop our acreage base in an effort to maximize its value and resource potential. We believe the location, concentration and scale of our core leasehold positions, coupled with our technical understanding of the reservoirs will allow us to efficiently develop our core area and to allocate capital to maximize the value of our resource base.
- *Operate our properties as a low-cost producer.* We believe our concentrated acreage position in the Eagle Ford and our experience as an operator of virtually all of our properties following completion of our recent oil and gas asset acquisitions enables us to apply optimized drilling and completion techniques, reduce operating costs and achieve economies of scale that will improve returns on capital investments. Operating control allows us to better manage timing and risk as well as the cost of infrastructure, drilling and ongoing operations. We generally drill multiple wells from a single pad, which reduces facilities costs and surface impact while also reducing unit costs and improving cycle time.
- *Utilize extensive acquisition and technical expertise to strategically grow our core acreage position*. We continuously evaluate resource development opportunities. To date, our management and technical teams have completed numerous acquisitions, and we expect to continue to identify and opportunistically lease or acquire additional acreage and producing assets to add to our multi-year drilling inventory.
- *Maintain financial discipline*. We intend to maintain a conservative financial position to allow us to develop our drilling, exploitation and exploration activities. Consistent with our disciplined approach to financial management, we have an active commodity hedging program that seeks to hedge a meaningful portion of our expected oil production, reducing our exposure to downside commodity price fluctuations and enabling us to protect cash flows and maintain liquidity to fund our capital program and investment opportunities. We plan to hedge a substantial portion of our anticipated crude oil production for 2018 and will expand additional hedging for the next several years on an opportunistic basis.

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 in the South Texas region 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 transportation services for a substantial portion of our natural gas production in the South Texas region until 2039.

Natural gas processing contracts. We have agreements that provide us with services to process our wet gas production into NGL products and dry, or residue, gas, encompassing our entire operating regions in South Texas and the Mid-Continent. We have two agreements attributable to the South Texas region that are evergreen in term with either party having the right to terminate with 30-days notice to the counterparty. We also have an agreement in place for the Mid-Continent region that extends through November 2019.

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, 2017, 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, 2017, approximately 86 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 natural 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, 2017, we have recorded asset retirement obligations of $3.3 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 natural 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. Litigation surrounding this rule is ongoing, and EPA has instituted rulemakings to both delay the effective date of this rule and repeal the rule.

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. 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 and Granite Wash formations. The EPA 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 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, Oklahoma and Texas have 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 natural 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 natural 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. 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, pending administrate review of the rule. These rules have required changes to our operations, including the installation of new equipment to control emissions. The EPA had also announced that it intends to impose methane emission standards for existing sources and has issued information collection requests for oil and natural 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 natural gas industry remain a possibility and could result in increased compliance costs on our operations.

In November 2015, the EPA also revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. Certain areas of the country previously in compliance with the various National Ambient Air Quality Standards, including areas where we operate, may be reclassified as non-attainment areas. The EPA has not yet designated which areas of the country are out of attainment with the new ground level ozone standard, and it will take the states several years to develop compliance plans for their non-attainment areas. If the areas where we operate are reclassified as non-attainment areas, such reclassifications may make it more difficult to construct new or modified sources of emission control in those 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 addition, on June 3, 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.

On August 3, 2015, the EPA also 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. The EPA's proposal will be subject to public comment and likely legal challenge, and as such we cannot predict at this time what impact the rulemaking will have on the demand for oil and natural gas production and our operations.

The EPA also 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 natural 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 natural gas projects.

Employees and Labor Relations

We had a total of 80 employees as of December 31, 2017. 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.

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 ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to 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;
- technological advances affecting energy consumption;
- 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, 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 natural gas;
- weather conditions; and
- domestic and foreign governmental relations, regulation and taxation.

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 and 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 drilling and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable oil or natural gas production. The costs of drilling, completing and operating wells are often substantial and uncertain, and drilling 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;
- 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, crews, equipment and materials;
- shortages in experienced labor;
- crude oil, NGLs or natural gas gathering, transportation and processing 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 approvals and permits;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- environmental hazards, such as natural gas leaks, oil 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; and
- adverse weather conditions.

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 completions delays and higher well costs in that region.

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. 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, nor can we 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.

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.

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

The oil and natural 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. 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. 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.

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.

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

Our business strategy has historically included maintaining a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. 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.

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 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 natural 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 2017, approximately 86 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 and currently depressed commodity environment 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 assumptions, including assumptions relating to crude oil, NGL and natural gas prices, drilling and operating expenses, capital expenditures, 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, therefore, changes often occur as these variables evolve and commodity prices fluctuate. Any material inaccuracies in these reserve 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, 2017, approximately 56 percent of our estimated proved reserves were proved undeveloped, compared to 47 percent at December 31, 2016. 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, 2017 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $663 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, 2017, we wrote-off 4.7 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 $443 million and $457 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, including $1.4 billion in 2015, while we applied the successful efforts method of accounting for oil and gas properties. We could experience additional write-downs in the future while applying the full cost method of accounting for oil and gas properties. While such a charge reflects our inability to recover the carrying value of our investments, it does not impact our cash flows from operating activities.

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.

We rely on third-party service providers to conduct the drilling and completion operations on properties we operate.

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.

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 and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and 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 and 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, 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 and financial condition. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forego 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. Our industry is highly competitive and we may not be able to compete effectively.

We 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 natural gas plays, to acquire new acreage, and to develop attractive oil and natural 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. 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.

Over 90 percent of our production, revenues and capital expenditures for 2017 were attributable to 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, 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 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;
- our ability to attract and retain customers may be negatively impacted;
- risks related to challenges to the Plan; and
- we may incur legal costs associated with addressing claims under the Plan.

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."

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 \$277 million of outstanding debt at December 31, 2017, including \$77 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.

As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business. We may incur substantially more debt in the future.

Any increase in our level of indebtedness could have adverse effects on our financial condition and results of operations, including imposing additional cash requirements on us in order to support interest payments, increasing our vulnerability to adverse changes in general economic and industry conditions and limiting our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes.

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 \$237.5 million as of December 31, 2017 and \$340 million as of March 1, 2018. Our borrowing base is redetermined at least twice each year and is scheduled to next be redetermined in October 2018. 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;
- pipeline ruptures or spills;
- 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 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.

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.

Laws and regulations restricting emissions of greenhouse gases 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 has begun 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*."

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*."

Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their greenhouse gas emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the company's causation of or contribution to the asserted damage, or to other mitigating factors.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and natural 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.

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. Moreover, 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 natural gas extraction.

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.

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. 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, though these rules have not been finalized.

While the CFTC has designated certain interest rate swaps and credit default swaps subject to mandatory clearing, the CFTC has not yet proposed rules subjecting any other classes of swaps, including physical commodity swaps, to mandatory clearing. 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 reduces 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, 2017, 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, due to the recently enacted budget reconciliation act commonly referred to as the Tax Cut and Jobs Act, or TCJA, U.S. NOLs generated on or after January 1, 2018 could be limited to 80 percent of taxable income.

Recently enacted legislation will affect our tax position, and one day, certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated. Additional state taxes on oil and natural gas extraction may be imposed, as a result of future legislation.

In December 2017, Congress enacted the TCJA. The law made significant changes to U.S. federal income tax laws, including reducing the corporate income tax rate to 21%, repeal of the corporate alternative minimum tax, or AMT, partially limiting the deductibility of interest expense and NOLs, eliminating the deduction for certain U.S. production activities, and allowing the immediate deduction of certain new investments in lieu of depreciation expense over time. Most of these new laws go into effect for tax years beginning after December 31, 2017. We are still evaluating the impact generated after December 31, 2017 of the TCJA to us. Notwithstanding the reduction in the corporate income tax rate and repeal of the corporate AMT, we cannot yet conclude that the overall impact of the TCJA to us is positive. The TCJA could adversely affect our business, operating results, financial condition and cash flows, as well as the value of an investment in our common stock.

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 natural 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. Although these changes were not included in the TCJA, 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 natural 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 natural 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 cyber 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. 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. 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.

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 relatively limited trading history subsequent to our emergence from bankruptcy, 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, 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. 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.

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 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, 2017, our primary oil and gas assets were located in Gonzales, Lavaca, Fayette and Dewitt Counties in South Texas and Washita and Custer Counties in Western Oklahoma.

Facilities

All of our office facilities are leased and we believe that our facilities 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
2017 (Successor)						
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 [2]	$51.34/Bbl	$18.48/Bbl	$2.98/MMBtu			
2016 (Successor)						
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 [2]	$42.75/Bbl	$12.33/Bbl	$2.48/MMBtu			
2015 (Predecessor)						
Developed						
Producing	19.6	6.1	36.8	31.8		
Non-producing	0.6	0.1	0.4	0.8		
	20.2	6.2	37.2	32.6		
Undeveloped	9.3	1.0	5.0	11.1		
	29.5	7.2	42.2	43.7	$ 323.3	$ 323.3
Price measurement used [2]	$50.28/Bbl	$14.44/Bbl	$2.70/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 and 2015 did not include any income tax effect. Accordingly, our PV10 and Standardized Measure values are equivalent as of those dates. 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.

[2] Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu. The representative prices of crude oil and natural gas, as adjusted for basis differentials and product quality, were as follows: crude oil - $50.06, $40.97 and $45.78 each per Bbl, NGLs - $18.02, $11.82 and $13.15 each per Bbl and natural gas - $2.89, $2.40 and $2.59 each per MMBtu, for December 31, 2017, 2016 and 2015, respectively. NGL prices were estimated as a percentage of the base crude oil price.

The following table sets forth by region the estimated quantities of proved reserves and the percentages thereof that are represented by proved developed reserves as of December 31, 2017:

Region	Proved Reserves	% of Total Proved Reserves	% Proved Developed
	(MMBOE)		
South Texas	70.2	97%	42%
Mid-Continent	2.4	3%	100%
	72.6	100%	44%

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, all of which are located in the Eagle Ford in South Texas, during the year ended December 31, 2017:

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	18.9	2.4	11.8	23.3
Revisions of previous estimates	(4.2)	(1.0)	(4.4)	(5.9)
Extensions and discoveries	22.3	3.0	15.0	27.7
Purchase of reserves	0.3	0.1	0.1	0.5
Conversion to proved developed reserves	(3.9)	(0.5)	(2.4)	(4.8)
Proved undeveloped reserves at end of year	33.4	4.0	20.1	40.8

In 2017, our proved undeveloped reserves increased by 17.5 MMBOE. We experienced negative revisions of 5.9 MMBOE including: (i) 4.7 MMBOE due to the loss of certain locations resulting from changes in the timing and drilling locations attributable to our development plans and (ii) 1.3 MMBOE due to reduced treatable lateral lengths in certain locations due primarily to reconfiguration of the planned drilling units partially offset by 0.1 MMBOE of other changes. Extensions and discoveries of 27.7 MMBOE are entirely attributable to our expanded development plan for the Eagle Ford including adding a third rig to our drilling program and the corresponding increase in the number of new drilling locations that we are planning to drill in the next five years. We acquired 0.5 MMBOE, as measured on the closing date of the transaction, in connection with the Devon Acquisition. In addition, we converted 4.8 MMBOE from proved undeveloped to proved developed reserves in the Eagle Ford. During 2017, we incurred capital expenditures of $74.9 million attributable to 25 gross (14.2 net) wells in connection with the conversion of proved undeveloped reserves to proved developed reserves. While we resumed our drilling program in November 2016, we did not turn any new wells to sales until February 2017 and we operated with only two rigs and limited completion service through the first half of 2017. Accordingly, our conversion rate for proved undeveloped reserves is anticipated to accelerate modestly from the actual rate achieved for 2017.

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 February 9, 2018, 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, 2017 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 Haynesville Shale and Cotton Valley in East Texas, which were sold in 2015 as "Divested properties." The sale of those operations represented a complete divestiture and we have retained no interests therein. In addition, we sold certain non-core properties in the Eagle Ford and Granite Wash in October 2015. The production associated with these former properties is also included within "Divested properties." Our remaining operations are represented in the Eagle Ford in South Texas and the Granite Wash in Oklahoma.

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	Year Ended December 31,
Region	2017	2016	2016	2015
	(MBOE)		(MBOE)	
South Texas	3,487	937	3,071	6,903
Mid-Continent and other [1]	292	103	276	460
Divested properties [2]	—	—	—	560
	3,779	1,040	3,346	7,923

	Average Daily Production			
	Successor		Predecessor	
	Year Ended December 31,	September 13 Through December 31,	January 1 Through September 12	Year Ended December 31,
Region	2017	2016	2016	2015
	(BOEPD)		(BOEPD)	
South Texas	9,553	8,518	11,996	18,913
Mid-Continent and other [1]	800	936	1,085	1,260
Divested properties [2]	—	—	—	2,150
	10,353	9,454	13,081	22,323

[1] Includes total production and average daily production of approximately 10 MBOE (48 BOEPD) and 22 MBOE (60 BOEPD) for 2016 and 2015, respectively, attributable to our then active Marcellus Shale wells.

[2] We sold all of our properties in the Haynesville Shale and Cotton Valley in East Texas in August 2015, which represented total production and average daily production of approximately 449 MBOE (1,806 BOEPD) in 2015. We sold certain non-core properties in the Eagle Ford and Granite Wash in October 2015, which represented total production and average daily production of approximately 111 MBOE (344 BOEPD) in 2015.

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	Year Ended December 31,
	2017	2016	2016	2015
Average prices:				
Crude oil ($ per Bbl)	$ 50.96	$ 46.63	$ 35.21	$ 44.81
NGLs ($ per Bbl)	$ 19.25	$ 16.51	$ 11.38	$ 12.24
Natural gas ($ per Mcf)	$ 2.89	$ 2.81	$ 2.06	$ 2.62
Aggregate ($ per BOE)	$ 42.20	$ 37.17	$ 27.99	$ 33.19
Average production and lifting cost ($ per BOE):				
Lease operating	$ 5.76	$ 5.13	$ 4.67	$ 5.36
Gathering processing and transportation	2.84	2.93	3.96	3.01
	$ 8.60	$ 8.06	$ 8.63	$ 8.37

Significant Fields

Our properties in the Eagle Ford in South Texas, which contain primarily crude oil reserves, represented approximately 97 percent of our total equivalent proved reserves as of December 31, 2017.

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12 2016	Year Ended December 31, 2015
Production: [1]				
Crude oil (MBbl)	2,716	695	2,265	4,733
NGLs (MBbl)	418	130	449	1,169
Natural gas (MMcf)	2,120	674	2,141	6,011
Total (MBOE)	3,487	937	3,071	6,903
Percent of total company production	92 %	90 %	92 %	87 %
Average prices:				
Crude oil ($ per Bbl)	$ 51.08	$ 46.73	$ 35.24	$ 44.73
NGLs ($ per Bbl)	$ 18.13	$ 14.82	$ 10.34	$ 11.03
Natural gas ($ per Mcf)	$ 2.95	$ 2.79	$ 2.05	$ 2.64
Aggregate ($ per BOE)	$ 43.74	$ 38.71	$ 28.94	$ 34.84
Average production and lifting cost ($ per BOE): [2]				
Lease operating	$ 5.79	$ 5.39	$ 4.58	$ 5.04
Gathering processing and transportation	2.49	2.58	3.50	2.66
	$ 8.28	$ 7.97	$ 8.08	$ 7.70

[1] Excludes production from certain non-core Eagle Ford properties that we sold in October 2015.
[2] Excludes production/severance and ad valorem taxes.

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, 2017, 2016 and 2015, 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.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	29	16.9	5	2.9	61	38.6
Dry well [1]	1	0.7	—	—	—	—
Total	30	17.6	5	2.9	61	38.6
Wells in progress at end of year [2]	11	8.2	5	2.6	4	2.3

[1] Represents the Zebra Hunter 05H well in the northern portion of our Eagle Ford acreage.
[2] Includes ten gross (7.4 net) wells completing or waiting on completion and one gross (0.8 net) well being drilled as of December 31, 2017.

Present Activities

As of December 31, 2017, we had 11 gross (8.2 net) wells in progress, all of which were located in the Eagle Ford in South Texas. As of February 23, 2018, seven gross (5.4 net) wells were completed, three gross (2.0 net) wells were completing or waiting on completion and one gross (0.8 net) well was the first well drilled on a three-well pad and will be prepared for completion with the other two wells upon drilling to total depth for this pad.

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 a gathering agreement with Republic Midstream, LLC, or Republic Midstream. Our production and reserves are currently sufficient to fulfill the current 8,000 BOPD delivery commitment under that agreement. 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.

Productive Wells

The following table sets forth by region the productive wells in which we had a working interest as of December 31, 2017:

	Primarily Oil		Primarily Natural Gas		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South Texas	402	289.2	1	1.0	403	290.2
Mid-Continent	2	1.6	95	41.1	97	42.7
	404	290.8	96	42.1	500	332.9

Of the total wells presented in the table above, we are the operator of 399 gross (367 oil and 32 gas) and 297.4 net (277.1 oil and 20.3 gas) wells. In addition to the above working interest wells, we own royalty interests in 19 gross wells.

Acreage

The following table sets forth by region our developed and undeveloped acreage as of December 31, 2017 (in thousands):

	Developed		Undeveloped		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South Texas	90.6	66.7	7.8	6.7	98.4	73.4
Mid-Continent and other	15.6	7.4	9.7	9.5	25.3	16.9
	106.2	74.1	17.5	16.2	123.7	90.3

The primary terms of our leases generally range from three to five years and we do not have any concessions. All of our acreage in the Granite Wash in Oklahoma is HBP. As of December 31, 2017, 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:

Region	**2018**	**2019**	**2020**	**Thereafter**
South Texas	2.7	0.8	3.1	0.1
Mid-Continent and other	0.0	9.5	0.0	0.0

We anticipate paying options to extend a substantial portion of the acreage scheduled to expire in South Texas in 2018. We do not believe that the remaining scheduled expirations of our undeveloped acreage in South Texas will substantially affect our ability or plans to conduct our exploration and development activities. In February 2018, we sold the our undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana that was scheduled to expire in 2019.

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. 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.

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

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

In connection with our reorganization and emergence from bankruptcy, our common stock was initially listed on the OTCQX U.S. Premier Market under the symbol "PVAC" on November 15, 2016. Prior to such time, there was no established trading market for our common stock. On December 28, 2016, our common stock was listed and began trading on the Nasdaq under the symbol "PVAC."

The market data below represents the high and low sales prices (composite transactions) of our common stock since November 15, 2016:

	Sales Price	
Quarter Ended	**High**	**Low**
December 31, 2017	$ 43.29	$ 32.99
September 30, 2017	$ 40.50	$ 33.44
June 30, 2017	$ 50.00	$ 31.00
March 31, 2017	$ 61.97	$ 41.40
December 31, 2016	$ 50.00	$ 34.75

Equity Holders

As of February 23, 2018, there were 109 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

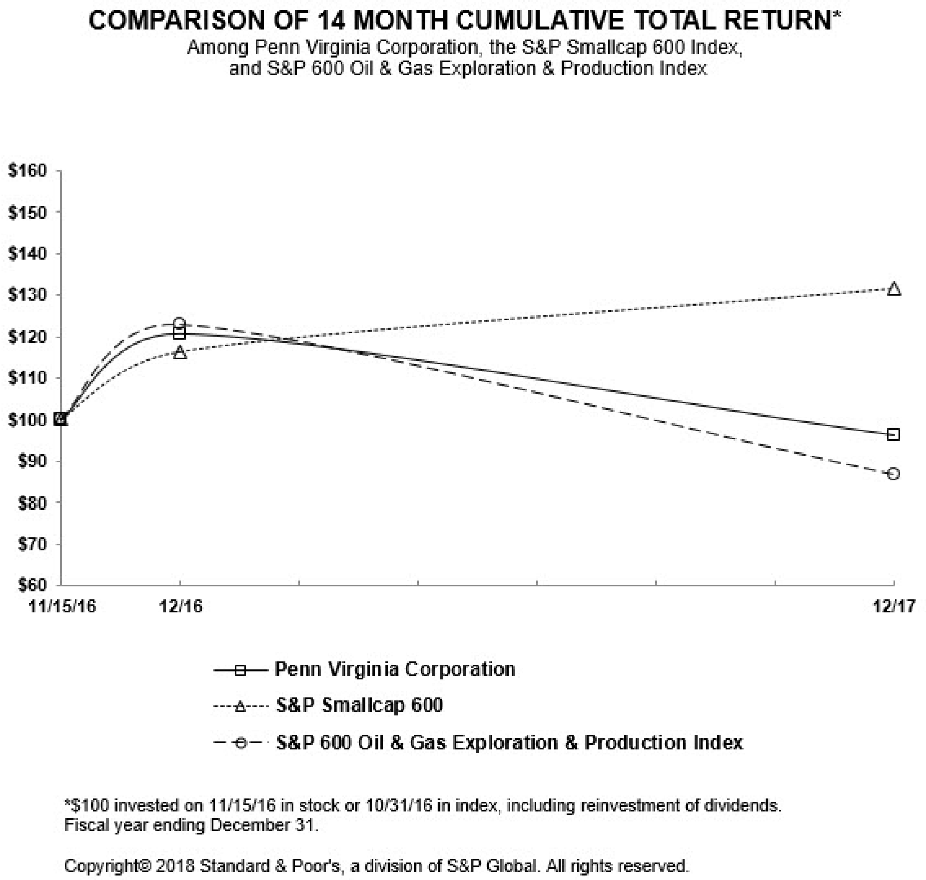
See Part III, Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" and Note 17 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for information regarding shares of common stock authorized 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 2017.

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 tradable) through December 31, 2017. As of December 31, 2017, there were five exploration and production companies in the Standard & Poor's 600 Oil & Gas Exploration and Production Index: Bill Barrett Corporation, Carrizo Oil & Gas, Inc., Denbury Resources Inc., PDC 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.



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

	November 15, 2016	December 31, 2016	December 31, 2017
Penn Virginia Corporation	$ 100.00	$ 120.62	$ 96.27
S&P SmallCap 600 Index	$ 100.00	$ 116.34	$ 131.74
S&P 600 Oil & Gas Exploration & Production Index	$ 100.00	$ 122.91	$ 86.71

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,		
	2017	2016	2016	2015	2014	2013
Statements of Operations and Other Data:						
Revenues	$ 160,054	$ 39,003	$ 94,310	$ 305,298	$ 636,773	$ 431,468
Operating income (loss) [1]	$ 51,811	$ 11,391	$ (20,856)	$ (1,565,041)	$ (615,985)	$ (92,046)
Net income (loss) [2]	$ 32,662	$ (5,296)	$ 1,054,602	$ (1,582,961)	$ (409,592)	$ (143,070)
Preferred stock dividends [3]	$ —	$ —	$ 5,972	$ 22,789	$ 17,148	$ 6,900
Income (loss) attributable to common shareholders [2]	$ 32,662	$ (5,296)	$ 1,048,630	$ (1,605,750)	$ (430,996)	$ (149,970)
Income (loss) per common share, basic	$ 2.18	$ (0.35)	$ 11.91	$ (21.81)	$ (6.26)	$ (2.41)
Income (loss) per common share, diluted	$ 2.17	$ (0.35)	$ 8.50	$ (21.81)	$ (6.26)	$ (2.41)
Weighted-average shares outstanding:						
Basic	14,996	14,992	88,013	73,639	68,887	62,335
Diluted	15,063	14,992	124,087	73,639	68,887	62,335
Dividends declared per share	$ —	$ —	$ —	$ —	$ —	$ —
Cash provided by operating activities	$ 81,710	$ 30,774	$ 30,247	$ 169,303	$ 282,724	$ 261,512
Cash paid for capital expenditures	$ 115,687	$ 4,812	$ 15,359	$ 364,844	$ 774,139	$ 504,203
Total production (MBOE)	3,779	1,039	3,346	7,923	7,934	6,824
	December 31,		September 12,	December 31,		
Balance Sheet and Other Data:	2017	2016	2016	2015	2014	2013
Property and equipment, net	$ 529,059	$ 247,473	$ 253,510	$ 344,395	$ 1,825,098	$ 2,237,304
Total assets	$ 629,597	$ 291,686	$ 333,974	$ 517,725	$ 2,201,810	$ 2,472,830
Total debt	$ 265,267	$ 25,000	$ 75,350	$ 1,224,383	$ 1,085,429	$ 1,252,808
Shareholders' equity (deficit)	$ 221,639	$ 185,548	$ 190,895	$ (915,121)	$ 675,817	$ 788,804
Actual shares outstanding at period-end	15,019	14,992	14,992	81,253	71,569	65,307
Proved reserves as of December 31, (MMBOE)	73	49	N/A	44	115	136

[1] Operating loss for 2015, 2014 and 2013 included impairment charges of $1.4 billion, $791.8 million and $132.2 million, respectively.

[2] Net income (loss) and Income (loss) attributable to common shareholders for the period of January 1 through September 12, 2016 includes reorganization items attributable to our bankruptcy proceedings of $1.1 billion.

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

ItemManagement's Discussion and Analysis of Financial Condition and Results of Operations 7

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 South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash.

While crude oil prices began 2017 in the $53 per Bbl range, they declined through the late winter and throughout the summer before climbing back and ending the year at approximately $60 per Bbl. With the improved pricing environment 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. Furthermore, many exploration and production companies that experienced financial difficulties similar to us during 2015 to 2016 time frame have restructured and refocused their financial resources and operating plans to capitalize on current opportunities. As a result, pricing for certain oilfield products and services, including drilling and completion services, have increased in the past several months.

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.

The following summarizes certain key operating and financial highlights for the three months ended December 31, 2017 with comparison to the three months ended September 30, 2017. The year-over-year highlights for 2017 and 2016 are addressed in further detail in the discussions for *Financial Condition* and *Results of Operations* that follow.

- Production increased approximately 31 percent to 1,135 MBOE, from 864 MBOE .
- Product revenues increased approximately 58 percent to $54.1 million from $34.3 million due primarily to the aforementioned increase in production as well as higher pricing for crude oil and NGLs partially offset by lower natural gas prices.
- Production and lifting costs increased on an absolute basis to $9.5 million from $7.6 million, but decreased on a per unit basis to $8.35 per BOE, from $8.85 per BOE due primarily to lower maintenance costs as well as the effect of the increase in production volume.
- Production and ad valorem taxes increased on an absolute and per unit basis to $3.0 million and $2.68 per BOE from $1.7 million and $1.93 per BOE, respectively, due primarily to higher production volume and product pricing.
- General and administrative expenses decreased on an absolute and per unit basis to $3.5 million and $3.05 per BOE from $7.0 million and $8.04 per BOE, respectively, due primarily to transaction costs associated with the Devon Acquisition and costs incurred to complete an upgrade of our ERP system, both of which were incurred in the third quarter of 2017, as well as the effect of higher production volume.
- Our DD&A increased to $17.1 million, or $15.07 per BOE from $10.7 million, or $12.33 per BOE due primarily to the increase in capitalized costs for oil and gas properties resulting from the Devon Acquisition and our expanded capital program as well as the effect of higher production volume.
- Our operating income increased to $21.2 million for the three months ended December 31, 2017 compared to $7.5 million for the three months ended September 30, 2017 due the combined impact of the matters noted 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	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Total production (MBOE)	3,779	1,039	3,346	7,923
Average daily production (BOEPD)	10,353	9,449	13,071	22,476
Crude oil production (MBbl)	2,764	710	2,311	4,923
Crude oil production as a percent of total	73%	68%	69%	62%
Product revenues	$ 159,469	$ 38,654	$ 93,649	$ 262,980
Crude oil revenues	$ 140,886	$ 33,157	$ 81,377	$ 220,596
Crude oil revenues as a percent of total	88%	86%	87%	84%
Realized prices:				
Crude oil ($ per Bbl)	$ 50.96	$ 46.68	$ 35.21	$ 44.81
NGL ($ per Bbl)	$ 19.25	$ 16.56	$ 11.37	$ 12.24
Natural gas ($ per Mcf)	$ 2.89	$ 2.81	$ 2.06	$ 2.62
Aggregate ($ per BOE)	$ 42.20	$ 37.19	$ 27.99	$ 33.18
Prices, adjusted for derivatives::				
Crude oil ($ per Bbl)	$ 49.69	$ 47.17	$ 55.98	$ 72.74
Natural gas ($ per Mcf)	$ 2.89	$ 2.81	$ 2.06	$ 2.69
Aggregate ($ per BOE)	$ 41.27	$ 37.56	$ 42.33	$ 50.63
Production and lifting costs ($ per BOE):				
Lease operating	$ 5.76	$ 5.13	$ 4.67	$ 5.36
Gathering, processing and transportation	$ 2.84	$ 2.93	$ 3.96	$ 3.01
Production and ad valorem taxes ($ per BOE)	$ 2.33	$ 2.40	$ 1.04	$ 2.06
General and administrative ($ per BOE) [1]	$ 4.83	$ 4.90	$ 11.64	$ 5.47
Depreciation, depletion and amortization ($ per BOE) [2]	$ 12.87	$ 11.21	$ 10.04	$ 42.22
Cash provided by operating activities [3]	$ 81,710	$ 30,774	$ 30,247	$ 169,303
Cash paid for capital expenditures	$ 115,687	$ 4,812	$ 15,359	$ 364,844
Cash and cash equivalents at end of period	$ 11,017	$ 6,761	$ 31,414	$ 11,955
Debt outstanding, net of discount and issue costs, at end of period	$ 265,267	$ 25,000	$ 75,350	$ 1,224,383
Credit available under credit facility at end of period [4]	$ 159,745	$ 102,233	$ 51,883	$ —
Net development wells drilled and completed	16.9	—	2.9	38.6
Proved reserves at the end of the period (MMBOE)	73	49	N/A	44

[1] Includes equity-classified share-based compensation, liability-classified share-based compensation and significant special charges, including acquisition transaction costs, strategic and financial advisory costs prior to our bankruptcy filing, among others as described in the discussion of *"Results of Operations - General and Administrative Expenses,"* of $1.35, $6.98 and $1.39 for the year ended December 31, 2017, the Predecessor period in 2016 and the year ended December 31, 2015, respectively.

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

[3] Includes cash paid for derivative settlements of $3.5 million for 2017 and cash received for derivative settlements of $0.4 million, $48.0 million and $138.2 million for the Successor period in 2016, the Predecessor period in 2016 and 2015, respectively.

[4] As of December 31, 2015, we were unable to draw on our pre-petition credit facility, or RBL.

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:

Acquisition of Producing Properties

Hunt Acquisition

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 has an effective date of October 1, 2017 and closed on March 1, 2018. We funded the Hunt Acquisition with borrowings under the Credit Facility. The Hunt Acquisition expands our core 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. As a result of the Hunt Acquisition we are the operator of substantially all of our Eagle Ford acreage.

Devon Acquisition

In July 2017, we entered into a purchase and sale agreement, or the Purchase Agreement, with Devon, to acquire all of Devon's right, title and interest in and to certain oil and gas assets, or the Devon Properties, including oil and gas leases covering approximately 19,600 net acres located primarily in Lavaca County, Texas for consideration of $205 million in cash, subject to adjustment, or the Devon Acquisition. Upon execution of the Purchase Agreement, we deposited $10.3 million as earnest money into an escrow account, or the Escrow Account. The Devon Acquisition has 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.

The final settlement 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 representing final adjustments for the period from the effective date of the acquisition through the closing date and the curing of title defects for certain properties. As of December 31, 2017, there was $3.2 million remaining in the Escrow Account, which is included as a component of noncurrent “Other assets” on our Consolidated Balance Sheet. Of this total, $2.5 million was transferred as described above and the remaining $0.7 million was distributed to us in February 2018.

Amendments to Credit Facility and Borrowing Base Redetermination

On March 1, 2018, we entered into an amendment to our Credit Facility that increased our borrowing base by $102.5 million to $340 million from $237.5 million pursuant to the Spring redetermination and the Hunt Acquisition.

Previously, in September 2017 and in connection with the closing of the Second Lien Facility (discussed below), the Credit Facility was amended to, among other things, increase the borrowing base to its year-end 2017 level of $237.5 million, provide for the entry into the Second Lien Facility, the borrowings thereunder, the granting of liens to secure the obligations thereunder and other related modifications.

Second Lien Facility

In September 2017, we entered into the Second Lien Facility. We received net proceeds of $187.8 million from the Second Lien Facility net of an original issue discount, or 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 Second Lien Facility was issued at a price of 98% with an initial interest rate of 8.34% resulting in an effective interest rate of 9.89%. The initial interest rate on the Second Lien Facility as described above was based on the three-month LIBOR rate in effect on the date the Second Lien Facility was entered into. As of March 1, 2018, the interest rate was 8.65%. The maturity date under the Second Lien Facility is September 29, 2022.

Production, Capital and Development Plans

Total production for the quarter and year ended December 31, 2017 was 1,135 MBOE and 3,779 MBOE, or 12,340 BOEPD and 10,353 BOEPD, with approximately 74 percent and 73 percent, or 845 MBbls and 2,764 MBbls, of production from crude oil, 13 percent and 14 percent from NGLs and 13 percent and 13 percent from natural gas, respectively. Production from our Eagle Ford operations during these periods was 1,067 MBOE and 3,487 MBOE, or 11,594 BOEPD and 9,553 BOEPD, respectively. Approximately 78 percent of our Eagle Ford production for each of the periods was from crude oil, 12 percent was from NGLs and 10 percent was from natural gas, respectively. Production from our Eagle Ford operations was approximately 94 percent and 92 percent of total Company production during the quarter and year ended December 31, 2017, respectively.

We drilled and turned nine and 29 gross (5.3 and 16.9 net) Eagle Ford wells to sales during the quarter and year ended December 31, 2017, respectively.

Based on our business plan, we anticipate total capital expenditures for 2018 to total between $320 and $360 million with approximately 95 percent of capital being directed to drilling and completions in the Eagle Ford.

Commodity Hedging Program

As of February 23, 2018, we have hedged a substantial portion of our estimated future crude oil production through the end of 2020. For 2018, we have 6,227 BOPD with a weighted-average WTI-based swap price of $50.70 per barrel and 2,500 BOPD with a weighted-average LLS-based swap price of $55.18 per barrel. For 2019, we have 4,915 BOPD with a weighted-average WTI-based swap price of $52.12 per barrel and 2,500 BOPD with a weighted-average LLS-based swap price of $51.30 per barrel. For 2020, we have 4,000 BOPD with a weighted-average WTI-based swap price of $52.67 per barrel. We are currently unhedged with respect to NGL and natural gas production.

Changes to Executive Management and Board of Directors

Effective August 15, 2017, our board of directors appointed John Brooks as our President and Chief Executive Officer and as a member of our board of directors. Furthermore, effective January 19, 2018, the Board increased the size of the Board to seven members and elected Mr. David Geenberg and Mr. Michael Hanna as members of the Board to fill the newly created vacancies. Additionally, effective February 28, 2018, Mr. Harry Quarls resigned from his position as a director and Executive Chairman of the Company, and the Board was reduced to six members. The Company is actively engaged in finding a new independent board member to serve as chairman of the board of directors of the Company. Until the Company can find such replacement, Darin G. Holderness and David Geenberg will serve as co-chairmen of the board.

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, as recently amended, provides us with up to $340 million in borrowing commitments. The current borrowing base under the Credit Facility is also $340 million. As of March 1, 2018, we had $164.2 million of availability under the Credit Facility, which reflects borrowings of $78.0 million drawn on March 1, 2018 to substantially fund the Hunt Acquisition.

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 substantial portion of our estimated future crude oil production through the end of 2020.

Our business plan contemplates capital expenditures in excess of our projected cash from operating activities for 2018. Subject to the variability of commodity prices and production that impacts our cash from operating activities, anticipated timing of our capital projects and unanticipated expenditures such as acquisitions, we plan to fund our 2018 capital program with cash from operating activities and borrowings under the Credit Facility.

Capital Resources

Under our business plan for 2018, we currently anticipate capital expenditures, excluding acquisitions, to total between $320 million and $360 million with approximately 95 percent of capital being directed to drilling and completions on our Eagle Ford acreage. We plan to fund our 2018 capital spending with cash from operating activities and borrowings under the Credit Facility. Based upon current price and production expectations for 2018, we believe that our cash from operating activities and borrowings under our Credit Facility will be sufficient to fund our operations through year-end 2018; 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 December 31, 2017, we had approximately $11 million of cash on hand. For additional information and an analysis of our historical cash from operating activities, see the "*Cash Flows*" discussion that follows.

Credit Facility Borrowings. During 2017, we borrowed $52 million, net of repayments, 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, 2017	$ 61,457	$ 77,000	4.53%
Year ended December 31, 2017	$ 41,840	$ 77,000	4.29%

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

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

Cash Flows

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

	Successor		Predecessor
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016
Cash flows from operating activities			
Operating cash flows, net of working capital changes	$ 91,365	$ 31,068	$ 34,914
Crude oil derivative settlements (paid) received, net	(3,511)	384	48,008
Interest payments, net of amounts capitalized	(4,102)	(598)	(4,331)
Income tax refunds	—	7	35
Acquisition transaction costs paid	(1,088)	—	—
Strategic and financial advisory fees paid	—	—	(18,036)
Reorganization items paid	(1,269)	(648)	(28,570)
Return of professional fee escrow	315	756	—
Restructuring and exit costs paid	—	(195)	(1,773)
Net cash provided by operating activities	81,710	30,774	30,247
Cash flows from investing activities			
Acquisitions, net	(200,849)	—	—
Capital expenditures	(115,687)	(4,812)	(15,359)
Proceeds from sales of assets, net	869	—	224
Other, net	—	(104)	1,186
Net cash used in investing activities	(315,667)	(4,916)	(13,949)
Cash flows from financing activities			
Proceeds (repayments) from credit facility borrowings, net	52,000	(50,350)	(43,771)
Proceeds from second lien facility, net	196,000	—	—
Debt issuance costs paid	(9,787)	—	(3,011)
Proceeds from rights offering, net	55	—	49,943
Other, net	(55)	(161)	—
Net cash provided by (used in) financing activities	238,213	(50,511)	3,161
Net increase (decrease) in cash and cash equivalents	$ 4,256	$ (24,653)	$ 19,459

Cash Flows from Operating Activities. The overall increase in net cash from operating activities for 2017 compared to the combined Successor and Predecessor periods in 2016 was primarily attributable to (i) higher prices resulting in higher overall product revenue receipts in 2017, (ii) substantially higher payments in the combined Successor and Predecessor periods in 2016 for professional fees and other costs associated with our reorganization, bankruptcy proceedings and consideration of strategic financing alternatives in advance thereof, (iii) payments for termination benefits and other exit activities in the combined Successor and Predecessor periods in 2016 and (iv) lower interest payments due to lower average outstanding borrowings under the Credit Facility and Second Lien Facility in 2017 as compared to outstanding borrowings under the Credit Facility and RBL in the combined Successor and Predecessor periods in 2016. The increase was partially offset by the effect of the payment of net cash settlements from derivatives in 2017 compared to the receipt of net settlements during the combined Successor and Predecessor periods in 2016. Specifically, our hedge prices under our derivative contracts were lower than actual WTI crude oil prices resulting in net payments in 2017 while the opposite situation occurred in the combined Successor and Predecessor periods in 2016 resulting in the receipt of cash settlements. Additionally, the early termination of certain pre-petition derivative contracts in the Predecessor period in 2016 accelerated the receipt of cash settlements in 2016. In addition, we (i) paid certain transaction costs associated with the Devon and Hunt Acquisitions in 2017 and (ii) experienced higher working capital utilization in 2017 as a result of the restart of our drilling program, which had been suspended from February 2016 through November 2016.

Cash Flows from Investing Activities. In 2017, we paid a total of $200.8 million for 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 2017 as compared to the combined Successor and Predecessor periods in 2016 due primarily to the restart of our Eagle Ford drilling program. Furthermore, the cash paid for capital expenditures in the Predecessor period in 2016 includes a higher portion attributable to settlements of accrued capital charges from the prior year-end period.

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

	Successor		Predecessor
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016
Drilling and completion	$ 125,235	$ 4,839	$ 3,696
Lease acquisitions and other land-related costs	4,493	93	58
Geological, geophysical (seismic) and delay rental costs	696	567	(16)
Pipeline, gathering facilities and other equipment, net	(597)	(45)	375
	$ 129,827	$ 5,454	$ 4,113

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:

	Successor		Predecessor
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016
Total capital program costs (from above)	$ 129,827	$ 5,454	$ 4,113
(Increase) decrease in accrued capitalized costs	(19,910)	(997)	11,301
Less:			
Exploration expenses charged to operations:			
Geological and geophysical (seismic) and delay rental costs	—	—	16
Transfers from tubular inventory and well materials	(3,326)	(272)	(465)
Sales & use tax refunds received and applied to property accounts	(2,265)	—	—
Add:			
Tubular inventory and well materials purchased in advance of drilling	6,252	61	211
Capitalized internal labor	2,384	541	—
Capitalized interest	2,725	25	183
Total cash paid for capital expenditures	$ 115,687	$ 4,812	$ 15,359

The increased capital expenditures for 2017 and the Predecessor period in 2016 were partially offset by cash inflows during such periods. We sold certain lease rights for inactive acreage in Oklahoma for $0.9 million in 2017 and the Predecessor period in 2016 includes insurance recoveries from a casualty loss incurred in 2015. The 2016 Successor period includes payments for certain items related to assets sold in prior periods net of proceeds received from the sale of surplus tubular inventory and well equipment.

Cash Flows from Financing Activities. The Successor periods in 2017 and 2016 include borrowings, net of repayments, of $52 million and $50.4 million, respectively, under the Credit Facility while the Predecessor period in 2016 includes repayments of $119.1 million under the RBL offset by the initial draw of $75.4 million under the Credit Facility upon emergence. We received proceeds of $196.0 million from the Second Lien Facility, net of OID, in 2017. We also paid $1.7 million of debt issue costs in 2017 in connection with amendments to the Credit Facility and $8.1 million in connection with the Second Lien Facility as compared to $3.0 million in the Predecessor period in 2016 attributable to the initial placement of the Credit Facility. Delayed receipts attributable to the rights offering in September 2016 were offset by costs paid in connection with the registration of our common stock in 2017 as compared to the original proceeds received from the rights offering in the 2016 Predecessor period upon our emergence from bankruptcy.

Capitalization

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

	December 31,	
	2017	2016
Credit Facility borrowings	$ 77,000	$ 25,000
Second Lien Facility term loans, net of original issue discount and issuance costs	188,267	—
Total debt	265,267	25,000
Shareholders' equity	221,639	185,548
Total capitalization	$ 486,906	$ 210,548
Debt as a % of total capitalization	54%	12%

Credit Facility. The Credit Facility provides for a $340 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 and 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 to pay expenses associated with our bankruptcy proceedings and for general corporate purposes including working capital. The Credit Facility matures in September 2020.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate, or LIBOR, plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on LIBOR borrowings is payable every one, three or six months, at our election, and is computed on the basis of a year of 360 days. As of December 31, 2017, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 4.78%. Unused commitment fees are charged at a rate of 0.50%.

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

Second Lien Facility. On September 29, 2017, we entered into the $200 million Second Lien Facility. We received $187.9 million from the Second Lien Facility, net of OID of $4.0 million and issue costs of $8.1 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%. 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, 2017, the actual interest rate on the Second Lien Facility was 8.57%. 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 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 3.75 to 1.00, decreasing on March 31, 2018 and thereafter to 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, 2017, 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 2017 and 2016 (the period from September 13 through December 31, 2016), the Predecessor period of 2016 (the period from January 1 through September 12, 2016) and the full calendar year of 2015. 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, impairments as well as exploration expenses), capital structure (specifically interest expense) and income taxes (due to the change in control). Accordingly, we believe that describing certain year-over-year variances and trends in our production, revenues and expenses for the calendar years 2017, 2016 and 2015 without regard to the concept of a Successor and Predecessor facilitates a meaningful analysis of our results of operations.

Substantial components of our year-over-year variances for 2016 to 2015 are due to the effects of property divestitures. In 2015, we sold all of our interests in the Haynesville Shale and Cotton Valley in East Texas as well as certain non-core properties in the Eagle Ford and Mid-Continent. In the discussion and analysis that follows, the term "Divested properties" refers to the production, revenues and expenses associated with our former assets in those regions. In addition, we operated three wells in the Marcellus Shale in Pennsylvania. We terminated operations in that region in August 2016 and completed well-plugging and remediation activities in 2017.

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, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Crude oil (MBbl)	2,764	711	2,311	4,923
NGLs (MBbl)	523	164	533	1,381
Natural gas (MMcf)	2,949	994	3,013	9,713
Total (MBOE)	3,779	1,040	3,346	7,923
2017 vs. Combined 2016 Variance (MBOE)			(607)	
% Change			(13.8)%	
Combined 2016 vs. 2015 Variance (MBOE)				(3,537)
% Change				(44.6)%

	Average Daily Production			
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Crude oil (Bbl per day)	7,573	6,463	9,028	13,523
NGLs (Bbl per day)	1,432	1,491	2,082	3,893
Natural gas (MMcf per day)	8	9	11	—
Total (BOEPD)	10,353	9,454	13,081	22,323
2017 vs. Combined 2016 Variance (MBOE)			(1,631)	
% Change			(13.6)%	
Combined 2016 vs. 2015 Variance (MBOE)				(10,339)
% Change				(46.3)%

	Total Production			
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
South Texas	3,487	937	3,071	6,903
Mid-Continent and other [1]	292	103	276	460
Divested properties [2]	—	—	—	560
Total (MBOE)	3,779	1,040	3,346	7,923
2017 vs. Combined 2016 Variance (MBOE)			(607)	
% Change			(13.8)%	
Combined 2016 vs. 2015 Variance (MBOE)				(3,537)
% Change				(44.6)%

	Average Daily Production			
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
South Texas	9,553	8,518	11,996	18,913
Mid-Continent and other [1]	800	936	1,085	1,260
Divested properties [2]	—	—	—	2,150
Total (BOEPD)	10,353	9,454	13,081	22,323
2017 vs. Combined 2016 Variance (MBOE)			(1,631)	
% Change			(13.6)%	
Combined 2016 vs. 2015 Variance (MBOE)				(10,339)
% Change				(46.3)%

[1] Includes total production and average daily production of approximately 10 MBOE (48 BOEPD) and 22 MBOE (60 BOEPD) for 2016 and 2015, respectively, attributable to our three then-active Marcellus Shale wells.

[2] We sold all of our properties in the Haynesville Shale and Cotton Valley in East Texas in August 2015, which represented total production and average daily production of approximately 449 MBOE (1,806 BOEPD) in 2015. We sold certain non-core properties in the Eagle Ford and Granite Wash in October 2015, which represented total production and average daily production of approximately 111 MBOE (344 BOEPD) in 2015.

2017 vs. 2016. Total production decreased for the year ended December 31, 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

2016 vs. 2015. Total production decreased substantially during the combined Successor and Predecessor periods in 2016 compared to 2015 due primarily to the suspension of our drilling program in February 2016, natural production declines in all of our operating regions and the sale of our East Texas assets in August 2015 and other non-core Eagle Ford and certain Mid-Continent properties in October 2015. Approximately 69 percent of total production during the combined Successor and Predecessor periods in 2016 was attributable to crude oil when compared to approximately 62 percent during 2015. Our Eagle Ford production represented approximately 91 percent of our total production during the combined Successor and Predecessor periods in 2016 compared to approximately 87 percent from this region during 2015. During the combined Successor and Predecessor period in 2016, we turned to sales five gross (2.9 net) Eagle Ford wells compared to 61 gross (38.6 net) Eagle Ford wells during 2015.

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:

	Successor		Predecessor	
	Total Product Revenues			
	Year Ended December 31, 2017	**September 13 Through December 31, 2016**	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**
Crude oil	$ 140,886	$ 33,157	$ 81,377	$ 220,596
NGLs	10,066	2,707	6,064	16,905
Natural gas	8,517	2,790	6,208	25,479
Total	$ 159,469	$ 38,654	$ 93,649	$ 262,980
2017 vs. Combined 2016 Variance			$ 27,166	
% Change			20.5 %	
Combined 2016 vs. 2015 Variance				$ (130,677)
% Change				(49.7)%

	Product Revenues per Unit of Volume			
	Year Ended December 31, 2017	**September 13 Through December 31, 2016**	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**
Crude oil ($ per barrel)	$ 50.96	$ 46.63	$ 35.21	$ 44.81
NGLs ($ per barrel)	$ 19.25	$ 16.51	$ 11.38	$ 12.24
Natural gas ($ per Mcf)	$ 2.89	$ 2.81	$ 2.06	$ 2.62
Total ($ per BOE)	$ 42.20	$ 37.17	$ 27.99	$ 33.19
2017 vs. Combined 2016 Variance ($ per BOE)			$ 12.03	
% Change			39.9 %	
Combined 2016 vs. 2015 Variance ($ per BOE)				$ (3.02)
% Change				(9.1)%

	Total Product Revenues			
	Year Ended December 31, 2017	**September 13 Through December 31, 2016**	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**
South Texas	$ 152,521	$ 36,261	$ 88,849	$ 240,486
Mid-Continent and other [1]	6,948	2,393	4,800	9,666
Divested properties [2]	—	—	—	12,828
Total	$ 159,469	$ 38,654	$ 93,649	$ 262,980
2017 vs. Combined 2016 Variance			$ 27,166	
% Change			20.5 %	
Combined 2016 vs. 2015 Variance				$ (130,677)
% Change				(49.7)%

	Product Revenues per Unit of Volume			
	Year Ended December 31, 2017	**September 13 Through December 31, 2016**	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**
South Texas	$ 43.74	$ 38.71	$ 28.94	$ 34.84
Mid-Continent and other	$ 23.79	$ 23.23	$ 17.41	$ 21.01
Divested properties	$ —	$ —	$ —	$ 22.91
Total ($ per BOE)	$ 42.20	$ 37.17	$ 27.99	$ 33.19
2017 vs. Combined 2016 Variance ($ per BOE)			$ 12.03	
% Change			39.9 %	
Combined 2016 vs. 2015 Variance ($ per BOE)				$ (3.02)
% Change				(9.1)%

[1] Includes revenues of $0.1 million and $0.2 million attributable to the Marcellus Shale for the Predecessor period in 2016 and the year ended December 31, 2015, respectively.

[2] Includes revenues of $8.2 million attributable to East Texas for 2015 that we sold in August 2015. Includes revenues of $4.3 million for 2015 attributable to non-core Eagle Ford properties that we sold in October 2015. Includes revenues of $0.4 million for 2015 attributable to certain Mid-Continent properties that we sold in October 2015.

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

	Year Ended December 31, 2017 vs. Combined Successor and Predecessor Periods Ended December 31, 2016			Combined Successor and Predecessor Periods Ended December 31, 2016 vs. Year Ended December 31, 2015		
	Revenue Variance Due to			Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ (9,742)	$ 36,094	$ 26,352	$ (85,180)	$ (20,882)	$ (106,062)
NGLs	(2,188)	3,483	1,295	(8,371)	237	(8,134)
Natural gas	(2,378)	1,897	(481)	(14,998)	(1,483)	(16,481)
	$ (14,308)	$ 41,474	$ 27,166	$ (108,549)	$ (22,128)	$ (130,677)

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 94 percent in the combined Successor and Predecessor periods in 2016.

2016 vs. 2015. Our product revenues during the combined Successor and Predecessor periods in 2016 decreased substantially compared to 2015 due primarily to the decline in production described previously, which was further exacerbated by the collapse of commodity prices that continued from 2015 into 2016. Total crude oil revenues were approximately 87 percent during the combined Successor and Predecessor periods in 2016 compared to 84 percent during 2015. Total Eagle Ford revenues were approximately 94 percent of total revenues in the combined Successor and Predecessor periods in 2016 compared to 91 percent in 2015.

Effects of Derivatives

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Crude oil revenues as reported	$ 140,886	$ 33,157	$ 81,377	$ 220,596
Derivative settlements, net	(3,511)	384	48,008	137,488
	$ 137,375	$ 33,541	$ 129,385	$ 358,084
Crude oil prices per Bbl, as reported	$ 50.96	$ 46.63	$ 35.21	$ 44.81
Derivative settlements per Bbl	(1.27)	0.54	20.77	27.93
	$ 49.69	$ 47.17	$ 55.98	$ 72.74
Natural gas revenues as reported	$ 8,517	$ 2,790	$ 6,208	$ 25,479
Derivative settlements, net	—	—	—	681
	$ 8,517	$ 2,790	$ 6,208	$ 26,160
Natural gas prices per Mcf, as reported	$ 2.89	$ 2.81	$ 2.06	$ 2.62
Derivative settlements per Mcf	—	—	—	0.07
	$ 2.89	$ 2.81	$ 2.06	$ 2.69

Gain (Loss) on Sales of Assets

During the Successor periods, 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 Predecessor periods, during which time we applied the successful efforts method, we also recognized gains and losses on the sale or disposition of oil and gas properties.

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Gain (loss) on sales of assets, net	$ (36)	$ (49)	$ 1,261	$ 41,335

2017 and Successor Period in 2016. In 2017 and the Successor period in 2016, we recognized insignificant net losses attributable to 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.

2015. In 2015, we recognized a gain of approximately $43 million on the sale of our East Texas assets. Additionally, in connection with an amendment to our crude oil gathering agreement with Republic Midstream which included a pricing concession, we recognized $8.4 million of the gain that was previously deferred and being recognized over the term of the underlying agreement. In 2015, we also recognized $0.4 million of deferred gain from the 2014 sale of our natural gas gathering and gas lift assets in South Texas. These gains were partially offset by a loss of $9.5 million from the sale of certain non-core Eagle Ford properties and a combined loss of $1.2 million from other sale transactions and post-closing adjustments attributable to prior year asset sales.

Other Revenues, net

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

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Other revenues, net	$ 621	$ 398	$ (600)	$ 983

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.

2016 vs. 2015. Other revenues, net decreased during the Successor and Predecessor periods in 2016 from 2015 due primarily to substantially lower drilling activity in our operating areas. Certain of these revenue sources also declined due to the sale of our East Texas assets in August 2015. In addition, we realized lower water supply and disposal fees in the South Texas region during the combined Successor and Predecessor periods in 2016 due to decreased demand in the region. We also reserved certain of our receivables from joint venture partners in the Predecessor period in 2016.

Lease Operating Expenses

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

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Lease operating	$ 21,784	$ 5,331	$ 15,626	$ 42,428
Per unit of production ($/BOE)	$ 5.76	$ 5.13	$ 4.67	$ 5.36

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 certain costs associated with maintaining our portfolio of operating wells, which are less variable in nature and are therefore adversely affected by lower production volume, as well as higher surface and other repair and maintenance costs. 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.

2016 vs. 2015. LOE decreased during the combined Successor and Predecessor periods in 2016 on an absolute and per unit basis when compared to 2015 due primarily to lower overall production and cost containment efforts that we implemented throughout 2016 and lower industry-wide pricing for certain oilfield products and services. The Predecessor period in 2015 included $4.2 million of LOE attributable to our East Texas assets that were sold in August 2015.

Gathering Processing and Transportation

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

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Gathering, processing and transportation	$ 10,734	$ 3,043	$ 13,235	$ 23,815
Per unit of production ($/BOE)	$ 2.84	$ 2.93	$ 3.96	$ 3.01

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 as discussed above 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 charges for production falling below our minimum commitments which were previously higher. We also incurred costs of approximately $0.5 million in the combined Successor and 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.

2016 vs. 2015. GPT decreased on an absolute basis during the combined Successor and Predecessor periods in 2016 when compared to 2015 due primarily to substantially lower production volumes in the South Texas region as discussed above. We also experienced a decline in the Successor and Predecessor periods in 2016 resulting from the sale of our East Texas assets in August 2015 as well as lower natural gas and NGL production in the Mid-Continent during the 2016 Successor and Predecessor periods when compared to 2015. The decrease in 2016 was partially offset by charges associated with volume deficiencies in 2016 attributable to our throughput commitments to Republic Midstream and Republic Midstream Marketing, LLC, or together, Republic, as well as higher costs for unused firm transportation services in the Marcellus Shale in the 2016 period prior to our termination of operations in that region. Per unit rates increased during the 2016 Successor and Predecessor periods primarily due to higher rates under the oil gathering services commenced by Republic Midstream in April 2016.

Production and Ad Valorem Taxes

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

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Production and ad valorem taxes				
Production/severance taxes	$ 7,533	$ 1,801	$ 2,695	$ 11,796
Ad valorem taxes	1,281	697	795	4,486
	$ 8,814	$ 2,498	$ 3,490	$ 16,282
Per unit of production ($/BOE)	$ 2.33	$ 2.40	$ 1.04	$ 2.06
Production/severance tax rate as a percent of product revenues	4.7%	4.7%	2.9%	4.4%

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 sales 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.

2016 vs. 2015. Production taxes in the South Texas region declined substantially during the combined Successor and Predecessor periods in 2016 when compared to 2015 due primarily to the overall decline in production volume and commodity prices. In the 2016 Predecessor period, we adjusted our accruals for ad valorem taxes downward, primarily in South Texas, reflecting lower oil and gas property valuations attributable to the significant decline in commodity prices. These adjustments resulted in a significant downward impact on the per unit cost for the Predecessor period in 2016. We also recognized certain severance tax refunds attributable to prior periods in the Mid-Continent and other region during the Predecessor period in 2016.

General and Administrative

Our general and administrative expenses, or G&A, 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 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, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Primary G&A	$ 13,133	$ 5,087	$ 15,596	$ 32,353
Shares-based compensation				
Liability-classified	—	—	(19)	(711)
Equity-classified	3,809	81	1,511	4,540
Significant special charges				
Acquisition transaction costs	1,340	—	—	—
Strategic and financial advisory costs	—	—	18,036	6,189
Restructuring expenses	(20)	(80)	3,821	957
Total general and administrative expenses	$ 18,262	$ 5,088	$ 38,945	$ 43,328
Per unit of production ($/BOE)	$ 4.83	$ 4.90	$ 11.64	$ 5.47
Per unit of production excluding all share-based compensation and other significant special charges identified above ($/BOE)	$ 3.48	$ 4.90	$ 4.66	$ 4.08

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 is attributable to the grants of time-vested restricted stock units, or RSUs, in the Successor periods in 2016 and 2017 as well as performance restricted stock units, or PRSUs, in 2017. The 2017 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.” 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. All of our equity-classified share-based compensation represents non-cash expenses.

During 2017, we incurred transaction costs associated with the Devon and 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.

2016 vs. 2015. Our primary G&A expenses decreased during the combined Successor and Predecessor periods in 2016 on an absolute basis and increased on a per unit basis compared to 2015. Our primary G&A expenses during the combined Successor and Predecessor periods in 2016 as compared to 2015 reflect the effects of: (i) lower payroll and benefits attributable to lower employee headcount, (ii) the relocation of our headquarters from Radnor, Pennsylvania to Houston, Texas and related move to a smaller office location, (iii) reduced travel and entertainment and (iv) lower corporate support costs.

Liability-classified share-based compensation represents unfavorable mark-to-market charges in the 2016 Predecessor period and 2015 associated with the change in fair value of the then outstanding PBRSU grants.

Equity-classified share-based compensation charges during the Successor period of 2016 were attributable to restricted stock unit grants to one executive and the board of directors in 2016, while the Predecessor periods in 2016 and 2015 were attributable to the Predecessor’s stock options and RSUs.

During the 2016 Predecessor period, 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 2015, we incurred $6.2 million in professional fees and consulting costs associated with certain strategic initiatives, including our refinancing efforts and a search for a chief executive officer.

In connection with our efforts to simplify and reduce our administrative cost structure, we terminated a total of 53 employees and incurred termination and severance benefits during the Predecessor period in 2016 as compared to a total of 26 employee terminations in 2015 for which we also incurred severance and termination benefits.

Exploration

While applying the successful efforts method of accounting to our oil and gas properties during the Predecessor period in 2016 and 2015, 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	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Unproved leasehold amortization	$ —	$ —	$ 1,940	$ 5,759
Drilling rig termination charges	—	—	1,705	5,885
Drilling carry commitment	—	—	1,964	—
Geological and geophysical costs (seismic)	—	—	33	828
Other, primarily write-off of uncompleted wells	—	—	4,646	111
	$ —	$ —	$ 10,288	$ 12,583

2016 vs. 2015. On the Emergence Date we adopted the full cost method. Accordingly, there are no exploration expenses recorded for the Successor period. With respect to the Predecessor period in 2016, we experienced lower unproved leasehold amortization attributable to a declining leasehold asset base subject to amortization. We also incurred early termination charges in connection with the release of drilling rigs in the Eagle Ford in each of the 2016 and 2015 Predecessor periods; however, the 2015 period includes the release of multiple rigs while the 2016 periods reflect the release of only one rig. Seismic and delay rental costs declined in the Predecessor period in 2016 compared to 2015 due to the suspension of our drilling program. These reductions were partially offset by a charge of $4.0 million for the write-off of certain uncompleted well costs prior to the aforementioned change in accounting method, a $2.0 million charge attributable to our failure to complete a drilling carry requirement attributable to certain acreage acquired in the Eagle Ford in 2014, and 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 period in 2016 as compared to the Predecessor periods in 2016 and 2015. 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	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
DD&A expense	$ 48,649	$ 11,652	$ 33,582	$ 334,479
DD&A rate ($/BOE)	$ 12.87	$ 11.21	$ 10.04	$ 42.22

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.

2016 vs. 2015. The effects of lower production volumes and lower depletion rates resulting from Fresh Start Accounting, impairments recorded in the fourth quarter of 2015 and an overall reduction in reserves in 2015 were the primary factors attributable to the decline in DD&A during the Successor and Predecessor periods in 2016 when compared to 2015.

Impairments

As more fully described in 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," our capitalized costs for oil and gas properties are subject to limitations during the Successor and Predecessor periods under the full cost and successful efforts methods, respectively.

The following table sets forth impairments charged for the periods presented:

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Impairments	$ —	$ —	$ —	$ 1,397,424

2016 vs. 2015. We had no impairments during the 2016 Successor period while we applied the full cost method and no impairments during the 2016 Predecessor period while we applied the successful efforts method. The significant deterioration of commodity prices throughout 2015, as reflected in the future strip pricing as of December 31, 2015, triggered an impairment of approximately $1.4 billion to our proved and unproved Eagle Ford properties and required us to reduce their carrying value to a fair value of approximately $312 million.

Interest Expense

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Interest on borrowings and related fees	$ 6,995	678	$ 36,012	$ 92,490
Accretion of original issue discount	161	—	—	—
Amortization of debt issuance costs	1,961	226	22,189	4,749
Capitalized interest	(2,725)	(25)	(183)	(6,288)
	$ 6,392	$ 879	$ 58,018	$ 90,951

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 the 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, 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 that was put in place at the end of the third quarter in 2017. 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

2016 vs. 2015. As described above, interest expense for the Successor period in 2016 is exclusively attributable to the Credit Facility. Interest expense during the Predecessor periods of 2016 and 2015 is attributable to the RBL and the Senior Notes. The 2016 Predecessor period also includes a $20.5 million accelerated write-off of our 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 commodity derivatives portfolio, by commodity type, for the periods presented:

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Crude oil derivative (losses) gains	$ (17,819)	$ (16,622)	$ (8,333)	$ 71,244
Natural gas derivative gains	—	—	—	3
	$ (17,819)	$ (16,622)	$ (8,333)	$ 71,247

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.

2016 vs. 2015. We received net cash settlements for crude oil derivatives during each of the Successor and Predecessor periods in 2016 and 2015 of $0.4 million, $48.0 million and $137.5 million, respectively, and received cash settlements of $0.7 million for natural gas derivatives during 2015. The decline in total cash settlements is attributable to: (i) lower spreads between hedged and realized prices on our post-petition derivatives, (ii) lower overall crude oil volumes hedged, (iii) the early termination of our entire pre-petition portfolio of 2016 derivative contracts, most of the proceeds from which were provided directly to the RBL lenders to pay down borrowings under the RBL prior to the Petition Date and (iv) the expiration of our natural gas hedges in the 2015 period.

Other, net

Other, net includes interest income and miscellaneous items of income and expense that are not directly associated with our current operations including 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, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Other, net	$ 119	$ 814	$ (3,184)	$ (3,587)

2017. In 2017, we recorded interest income attributable to the Escrow Account and we recovered 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.

2015. In 2015, we wrote-off a combined $1.6 million of receivables from various joint interest partners and other parties that we determined were not collectible as well as approximately $2.0 million of unrecoverable amounts from prior years, including GPT and other revenue deductions, attributable primarily to properties that have been sold.

Reorganization Items, net

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Gains on the settlement of liabilities subject to compromise	$ —	$ —	$ 1,150,248	$ —
Fresh Start Accounting adjustments	—	—	28,319	—
Legal and professional fees and expenses	—	—	(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	—	—	(46)	—
	$ —	$ —	$ 1,144,993	$ —

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 benefits for the periods presented:

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Income tax benefit	$ 4,943	$ —	$ —	$ 5,371
Effective tax benefit rate	17.8%	—%	—%	0.3%

2017. In connection with our initial 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 corporate alternative minimum tax, or AMT, we anticipate that our existing AMT credit carryovers will become refundable beginning with the 2018 tax year. The AMT credit carryforwards will be 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 full utilization of the AMT credit carryforwards by 2021.

In addition to the aforementioned offsetting items with respect to the reduction in income tax rates, our income tax provision includes 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 the AMT matter.

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.

We evaluated the impact of our reorganization, including the change in control, resulting from our emergence from bankruptcy. From an income tax perspective, the most significant impact is attributable to our carryover tax attributes associated with our NOLs. We believe that the Successor will be able to fully absorb the cancellation of debt income realized by the Predecessor in connection with the reorganization with its adjusted NOL carryovers. The amount of the remaining NOL carryovers and the tax basis of our properties will be limited under Section 382 of the Internal Revenue Code due to the change in control as described in Note 4 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." As the tax basis of our assets, primarily our oil and gas properties, is in excess of the carrying value, as adjusted in the Fresh Start Accounting process, the Successor is in a net deferred tax asset position.

2015. We recognized a federal income tax benefit for 2015 at the statutory rate of 35%; however, the federal tax benefit was substantially offset by a valuation allowance against our net deferred tax assets. We recognized state deferred tax benefits of $4.4 million as well as certain federal deferred tax benefits of $1.0 million resulting in a combined effective tax rate of 0.3% for 2015. The significant difference between our combined federal and state statutory rate of 35.7% and our effective tax of 0.3% is due almost entirely to the incremental valuation allowance placed against our deferred tax assets.

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, 2017, 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. 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, 2017:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Credit Facility [1]	$ 77,000	$ —	$ 77,000	$ —	$ —
Second Lien Facility [2]	200,000	—	—	200,000	—
Interest payments on long-term debt [3]	91,228	20,824	40,538	29,866	—
Operating leases [4]	366	241	125	—	—
Crude oil gathering and transportation commitments [5]	124,676	10,376	24,664	25,924	63,712
Drilling and completion commitments [6]	37,907	37,907	—	—	—
Asset retirement obligations [7]	89,575	—	—	—	89,575
Derivatives	41,677	27,777	13,900	—	—
Other commitments [8]	262	157	100	5	—
Total contractual obligations	$ 662,691	$ 97,282	$ 156,327	$ 255,795	$ 153,287

[1] Assumes that the amount outstanding of $77 million as of December 31, 2017 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, 2017 will remain outstanding until its maturity in 2022. The Second Lien 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 the amounts outstanding of $77 million and $200 million as of December 31, 2017, respectively, will remain outstanding until their maturities in 2020 and 2022, respectively.

[4] Relates primarily to office 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 commitments for two drilling rigs, one frac service crew and certain proppant materials.

[7] Represents the undiscounted balance payable, primarily for the plugging of inactive wells, in periods more than five years in the future for which $3.3 million, on a discounted basis, has been recognized on our Consolidated Balance Sheet as of December 31, 2017. 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, 2017, the carrying value of our proved oil and gas properties was below the limit determined by the Ceiling Test by approximately $213 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 and interest rate fluctuations. The derivative financial instruments, which are placed with financial institutions that we believe are of acceptable credit risk, take the form of collars, swaps and swaptions, 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 and rates. 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, 2017, we had a full valuation allowance for all of our net deferred tax assets, with the exception of our 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 March 2017, the Financial Accounting Standards Board, or the FASB, issued Accounting Standards Update, or ASU, 2017–07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, or ASU 2017–07, which provides guidance to improve the reporting of net benefit cost in financial statements. The guidance requires employers to disaggregate the service cost component from the other components of net benefit cost. The service cost component of net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period, except for amounts capitalized. All other components of net benefit cost shall be presented outside of a subtotal for income from operations. The line item used to present the components other than the service cost shall be disclosed if the other components are not presented in a separate line item or items. ASU 2017–07 is effective January 1, 2018 and is required to be applied retrospectively. ASU 2017–07 will be applicable to our legacy retiree benefit plans which cover a limited population of former employees. There is no service cost associated with these plans as they are not applicable to current employees, but rather interest and other costs associated with the legacy obligations. Upon the adoption of ASU 2017–07, the entirety of the expense associated with these plans will be presented as a component of the “Other income (expense)” caption in our Consolidated Statement of Operations. These costs are currently recognized as a component of “General and administrative” expenses. The total cost associated with these plans is generally less than $0.1 million on an annual basis and is therefore not material. We have adopted ASU 2017–07 effective as of January 2018.

In June 2016, the FASB issued ASU 2016–13, *Measurement of Credit Losses on Financial Instruments*, or ASU 2016–13, which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold, (an “incurred loss” model), ASU 2016–13 mandates an “expected loss” model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and 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. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–02 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASU 2016–02 is January 1, 2019, with early adoption permitted. We believe that ASU 2016–02 will likely be applicable to our oil and natural gas gathering commitment arrangements as described in Note 15 to our Consolidated Financial Statements included in Part II, Item 8, included in Part II, Item 8, “Financial Statements and Supplementary Data,” our existing leases for office facilities and certain office equipment, land easements and similar arrangements for rights-of-way and potentially to certain drilling rig and completion contracts with terms in excess of twelve months to the extent we may have such contracts in the future. Our oil and natural gas gathering arrangements are fairly complex and involve multiple elements that could be construed as leases. Accordingly, we are continuing to evaluate the effect that ASU 2016–02 will have on our Consolidated Financial Statements and related disclosures as well as the period for which we will adopt the standard; however, at this time, we believe that we will likely adopt ASU 2016–02 in 2019. We are also continuing to monitor developments regarding ASU 2016–02 that are unique to our industry.

In May 2014, the FASB issued ASU 2014–09, *Revenues from Contracts with Customers*, or ASU 2014–09, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. While traditional commodity sales transactions, property conveyances and joint interest arrangements in the oil and gas industry are not expected to be significantly impacted by ASU 2014–09, the terms of the individual commodity purchase, joint operating agreements and other contracts underlying these types of transactions will determine the appropriate recognition, measurement and disclosure once ASU 2014–09 has been adopted. Also, to the extent applicable, participation in certain of these transactions as either a principal or agent can impact the ultimate accounting and presentation.

We have adopted ASU 2014–09 using the cumulative effect transition method, effective as of January 2018. We will record a cumulative-effect charge to our beginning balance of retained earnings for $2.6 million representing the net receivables for producer imbalances as December 31, 2017, the accounting for which has been modified under ASU 2014–09. Effective January 2018, we will discontinue utilization of the “entitlements” method for producer imbalances and will begin accounting for such transactions utilizing the “sales” method. We do not anticipate this change to have a material impact going forward. In addition, we will change the presentation of our NGL product revenues from a “gross” to a “net” basis, that is revenues, net of processing costs, as we have determined that we are the agent with respect to the sale of these products to the ultimate customers. Accordingly, the applicable processing costs associated with these revenues will no longer be presented as a component of “Gathering, processing and transportation” expense on our Consolidated Statement of Operations. In summary, with the exception of the presentation of NGL revenues and more expansive disclosures, we do not anticipate a material impact attributable to the adoption of ASU 2014–09.

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, 2017, we had borrowings of $77 million under the Credit Facility at an interest rate of 4.78%. As of December 31, 2017, we had borrowings of $188.3 million under the Second Lien Facility , net of OID and issuance costs, at an interest rate of 8.57%. 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 $2.8 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, swaps and swaptions) 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 have not typically entered into derivative instruments with respect to NGLs, although we may do so in the future.

As of December 31, 2017, we reported a commodity derivative liability of $41.7 million. The net and gross amounts for our derivative assets and liabilities are the same for both periods presented above. The contracts associated with this position are with five 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, 2017, we reported net commodity derivative losses of $17.8 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, 2017:

	Instrument [1]	Average Volume Per Day	Weighted Average Price	Fair Value Asset	Fair Value Liability
Crude Oil:		**(barrels)**	**($/barrel)**		
First quarter 2018	Swaps	8,013	$ 51.14	$ —	$ 7,622
Second quarter 2018	Swaps	7,984	$ 51.15	—	7,075
Third quarter 2018	Swaps	7,955	$ 51.15	—	6,241
Fourth quarter 2018	Swaps	7,955	$ 51.15	—	5,357
First quarter 2019	Swaps	6,446	$ 50.97	—	3,845
Second quarter 2019	Swaps	6,421	$ 50.97	—	3,336
Third quarter 2019	Swaps	6,397	$ 50.97	—	2,886
Fourth quarter 2019	Swaps	6,398	$ 50.97	—	2,528
First quarter 2020	Swaps	2,000	$ 51.29	—	441
Second quarter 2020	Swaps	2,000	$ 51.29	—	353
Third quarter 2020	Swaps	2,000	$ 51.29	—	283
Fourth quarter 2020	Swaps	2,000	$ 51.29	—	228

[1] Including the effect of additional hedge contracts entered into in January 2018, we have hedged our crude oil production as follows: 2018 - 6,227 BOPD at a weighted-average WTI-based price of $50.70 per barrel and 2,500 BOPD at a weighted-average LLS-based price of $55.18 per barrel, 2019 - 4,915 BOPD at a weighted-average WTI-based price of $52.12 per barrel and 2,500 BOPD at a weighted-average LLS-based price of $51.30 per barrel and 2020 - 4,000 BOPD at a weighted-average WTI-based price of $52.67 per barrel.

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 prices, natural gas prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

	Change of $10.00 per Barrel of Crude Oil or $1.00 per MMBtu of Natural Gas ($ in millions) Increase	Decrease
Effect on the fair value of crude oil derivatives	$ (61.3)	$ 55.7
Effect on 2018 operating income, excluding crude oil derivatives [1]	$ 65.8	$ (65.8)
Effect on 2018 operating income, excluding natural gas derivatives [1]	$ 4.8	$ (4.8)

[1] Based on our 2018 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, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for the year ended December 31, 2017 (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, 2017 and 2016, and the results of their operations and their cash flows for the year ended December 31, 2017 (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, 2017, 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 March 2, 2018 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
March 2, 2018

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, 2017, 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, 2017, 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, 2017, and our report dated March 2, 2018 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
March 2, 2018

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows of Penn Virginia and subsidiaries for the year ended December 31, 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and the cash flows of Penn Virginia Corporation and subsidiaries for the year ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in note 2 to the consolidated financial statements in the 2015 Form 10-K, the Company has suffered recurring losses from operations and is dependent on obtaining additional financing to continue its planned principal business operations. These factors raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in note 2 to the consolidated financial statements in the 2015 Form 10-K. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ KPMG LLP

Houston, Texas
March 15, 2016

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13, Through December 31, 2016	January 1, Through September 12, 2016	Year Ended December 31, 2015
Revenues				
Crude oil	$ 140,886	$ 33,157	$ 81,377	$ 220,596
Natural gas liquids	10,066	2,707	6,064	16,905
Natural gas	8,517	2,790	6,208	25,479
Gain (loss) on sales of assets, net	(36)	(49)	1,261	41,335
Other, net	621	398	(600)	983
Total revenues	160,054	39,003	94,310	305,298
Operating expenses				
Lease operating	21,784	5,331	15,626	42,428
Gathering, processing and transportation	10,734	3,043	13,235	23,815
Production and ad valorem taxes	8,814	2,498	3,490	16,282
General and administrative	18,262	5,088	38,945	43,328
Exploration	—	—	10,288	12,583
Depreciation, depletion and amortization	48,649	11,652	33,582	334,479
Impairments	—	—	—	1,397,424
Total operating expenses	108,243	27,612	115,166	1,870,339
Operating income (loss)	51,811	11,391	(20,856)	(1,565,041)
Other income (expense)				
Interest expense, net of amounts capitalized	(6,392)	(879)	(58,018)	(90,951)
Derivatives	(17,819)	(16,622)	(8,333)	71,247
Other, net	119	814	(3,184)	(3,587)
Reorganization items, net	—	—	1,144,993	—
Income (loss) before income taxes	27,719	(5,296)	1,054,602	(1,588,332)
Income tax benefit	4,943	—	—	5,371
Net income (loss)	32,662	(5,296)	1,054,602	(1,582,961)
Preferred stock dividends	—	—	(5,972)	(22,789)
Net income (loss) attributable to common shareholders	$ 32,662	$ (5,296)	$ 1,048,630	$ (1,605,750)
Net income (loss) per share:				
Basic	$ 2.18	$ (0.35)	$ 11.91	$ (21.81)
Diluted	$ 2.17	$ (0.35)	$ 8.50	$ (21.81)
Weighted average shares outstanding – basic	14,996	14,992	88,013	73,639
Weighted average shares outstanding – diluted	15,063	14,992	124,087	73,639

See accompanying notes to consolidated financial statements.

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

	Successor		Predecessor	
	Year Ended December 31, 2017	**September 13 Through December 31, 2016**	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**
Net income (loss)	$ 32,662	$ (5,296)	$ 1,054,602	$ (1,582,961)
Other comprehensive income (loss):				
Change in pension and postretirement obligations, net of tax of $0 for 2017, $39 for the Successor period from September 13, 2016 through December 31, 2016, $(226) for the Predecessor period from January 1, 2016 through September 12, 2016, and $93 for 2015.	(73)	73	(421)	173
	(73)	73	(421)	173
Comprehensive income (loss)	$ 32,589	$ (5,223)	$ 1,054,181	$ (1,582,788)

See accompanying notes to consolidated financial statements.

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

	December 31, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$ 11,017	$ 6,761
Accounts receivable, net of allowance for doubtful accounts	69,821	29,095
Other current assets	6,250	3,028
Total current assets	87,088	38,884
Property and equipment, net	529,059	247,473
Deferred income taxes	4,943	—
Other assets	8,507	5,329
Total assets	$ 629,597	$ 291,686
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 96,181	$ 49,697
Derivative liabilities	27,777	12,932
Total current liabilities	123,958	62,629
Other liabilities	4,833	4,072
Derivative liabilities	13,900	14,437
Long-term debt	265,267	25,000
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; 15,018,870 and 14,992,018 shares issued as of December 31, 2017 and December 31, 2016, respectively	150	150
Paid-in capital	194,123	190,621
Retained earnings (accumulated deficit)	27,366	(5,296)
Accumulated other comprehensive income	—	73
Total shareholders' equity	221,639	185,548
Total liabilities and shareholders' equity	$ 629,597	$ 291,686

See accompanying notes to consolidated financial statements.

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Cash flows from operating activities				
Net income (loss)	$ 32,662	$ (5,296)	$ 1,054,602	$ (1,582,961)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash reorganization items	—	—	(1,178,302)	—
Depreciation, depletion and amortization	48,649	11,652	33,582	334,479
Impairments	—	—	—	1,397,424
Accretion of firm transportation obligation	—	—	317	942
Derivative contracts:				
Net losses (gains)	17,819	16,622	8,333	(71,247)
Cash settlements, net	(3,511)	384	48,008	138,169
Deferred income tax benefit	(4,943)	—	—	(4,712)
Loss (gain) on sales of assets, net	36	49	(1,261)	(41,335)
Non-cash exploration expense	—	—	6,038	5,759
Non-cash interest expense	2,122	226	22,189	4,749
Share-based compensation (equity-classified)	3,809	81	1,511	4,540
Other, net	61	21	(13)	13
Changes in operating assets and liabilities:				
Accounts receivable, net	(43,318)	10,791	12,273	137,854
Accounts payable and accrued expenses	28,542	(3,887)	22,469	(152,553)
Other assets and liabilities	(218)	131	501	(1,818)
Net cash provided by operating activities	81,710	30,774	30,247	169,303
Cash flows from investing activities				
Acquisitions, net	(200,849)	—	—	—
Capital expenditures	(115,687)	(4,812)	(15,359)	(364,844)
Proceeds from sales of assets, net	869	—	224	85,189
Other, net	—	(104)	1,186	—
Net cash used in investing activities	(315,667)	(4,916)	(13,949)	(279,655)
Cash flows from financing activities				
Proceeds from credit facility borrowings	59,000	—	75,350	233,000
Repayment of credit facility borrowings	(7,000)	(50,350)	(119,121)	(98,000)
Proceeds from second line note	196,000	—	—	—
Debt issuance costs paid	(9,787)	—	(3,011)	(744)
Proceeds received from rights offering, net	55	—	49,943	—
Dividends paid on preferred stock	—	—	—	(18,201)
Other, net	(55)	(161)	—	—
Net cash provided by (used in) financing activities	238,213	(50,511)	3,161	116,055
Net increase (decrease) in cash and cash equivalents	4,256	(24,653)	19,459	5,703
Cash and cash equivalents - beginning of period	6,761	31,414	11,955	6,252
Cash and cash equivalents - end of period	$ 11,017	$ 6,761	$ 31,414	$ 11,955
Supplemental disclosures:				
Cash paid for interest (net of amounts capitalized)	$ 4,102	$ 598	$ 4,331	$ 86,226
Cash paid for income taxes (net of refunds)	$ —	$ (7)	$ (35)	$ (714)
Cash paid for reorganization items, net	$ 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	$ 19,910	$ 997	$ (11,301)	$ (55,660)
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, 2014 (Predecessor)	71,569	$ 4,044	$ 529	$ 1,206,305	$ (535,176)	$ 3,211	$ 249	$ (3,345)	$ 675,817
Net loss	—	—	—	—	(1,582,961)	—	—	—	(1,582,961)
Conversion of preferred stock	9,414	(898)	94	804	—	—	—	—	—
Dividends declared on preferred stock ($300.00 and $300.00 per Series A and Series B preferred share, respectively)	—	—	—	—	(12,134)	—	—	—	(12,134)
Share-based compensation	195	—	4	4,536	—	—	—	—	4,540
Deferred compensation	2	—	—	—	—	229	—	(229)	—
Restricted stock unit vesting	73	—	1	(557)	—	—	—	—	(556)
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	173	—	173
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

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 South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash.

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, with the exception of an oil and gas asset acquisition described in Note 5, no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes thereto.

Recently Issued Accounting Pronouncements Pending Adoption

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

In June 2016, the FASB issued ASU 2016–13, *Measurement of Credit Losses on Financial Instruments* ("ASU 2016–13"), which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold, (an "incurred loss" model), ASU 2016–13 mandates an "expected loss" model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and 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* ("ASU 2016–02"), which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than twelve months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–02 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASU 2016–02 is January 1, 2019, with early adoption permitted. We believe that ASU 2016–02 will likely be applicable to our oil and natural gas gathering commitment arrangements as described in Note 15, our existing leases for office facilities and certain office equipment, land easements and similar arrangements for rights-of-way and potentially to certain drilling rig and completion contracts with terms in excess of twelve months to the extent we may have such contracts in the future. Our oil and natural gas gathering arrangements are fairly complex and involve multiple elements that could be construed as leases. Accordingly, we are continuing to evaluate the effect that ASU 2016–02 will have on our Consolidated Financial Statements and related disclosures as well as the period for which we will adopt the standard; however, at this time, we believe that we will likely adopt ASU 2016–02 in 2019. We are also continuing to monitor developments regarding ASU 2016–02 that are unique to our industry.

In May 2014, the FASB issued ASU 2014–09, *Revenues from Contracts with Customers* ("ASU 2014–09"), which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. While traditional commodity sales transactions, property conveyances and joint interest arrangements in the oil and gas industry are not expected to be significantly impacted by ASU 2014–09, the terms of the individual commodity purchase, joint operating agreements and other contracts underlying these types of transactions will determine the appropriate recognition, measurement and disclosure once ASU 2014–09 has been adopted. Also, to the extent applicable, participation in certain of these transactions as either a principal or agent can impact the ultimate accounting and presentation.

We have adopted ASU 2014–09 effective January 2018 using the cumulative effect transition method. We will record a cumulative-effect charge to our beginning balance of retained earnings for $2.6 million representing the net receivables for producer imbalances as December 31, 2017, the accounting for which has been modified under ASU 2014–09. Effective January 2018, we will discontinue utilization of the "entitlements" method for producer imbalances and will begin accounting for such transactions utilizing the "sales" method. We do not anticipate this change to have a material impact going forward. In addition, we will change the presentation of our NGL product revenues from a "gross" to a "net" basis, that is revenues, net of processing costs, as we have determined that we are the agent with respect to the sale of these products to the ultimate customers. Accordingly, the applicable processing costs associated with these revenues will no longer be presented as a component of "Gathering, processing and transportation" expense on our Consolidated Statement of Operations. In summary, with the exception of the presentation of NGL revenues and more expansive disclosures, we do not anticipate a material impact attributable to the adoption of ASU 2014–09.

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, take the form of collars, swaps and swaptions. 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 and in the fourth quarter based on our year-end reserve report through December 31, 2015.

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, such as roads and land 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

We record revenues associated with sales of crude oil, NGLs and natural gas when title passes to the customer. Through December 31, 2017, we recognized natural gas sales revenues from properties in which we have an interest with other producers on the basis of our net revenue interest ("entitlement" method of accounting - see Note 2 regarding the adoption of ASU 2014–09 effective January 2018). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of natural gas production. We treat any amount received in excess of our share as a liability. If we take less than we are entitled to take, we record the under-delivery as a receivable. 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, particularly from properties that are operated by our partners. 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.

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 January 31, 2018, the Bankruptcy Court closed the eight cases attributable to the Chapter 11 Subsidiaries, leaving the aforementioned lead case open pending the entry of a final decree or order by the Bankruptcy Court.

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: Darin G. Holderness, CPA, Marc McCarthy and Harry Quarls and, in October 2016, Jerry R. Schuyler;
- 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.

While our emergence from bankruptcy is effectively complete, certain administrative and claims resolution activities will continue under the authority of the Bankruptcy Court until they have been appropriately discharged. As of February 23, 2018, certain claims were still in the process of resolution. While most of these matters are unsecured claims for which shares of Successor Common Stock have been allocated, certain of these matters must be settled with cash payments. As of December 31, 2017, we had $3.9 million reserved for outstanding claims to be potentially settled in cash. This reserve is included as a component of "Accounts payable and accrued liabilities" on our Consolidated Balance Sheet.

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.

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

		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		(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		(46)
	$	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 and Lavaca Counties, Texas for $86.0 million in cash, subject to adjustments (the "Hunt Acquisition"). The Hunt Acquisition has an effective date of October 1, 2017 and closed on March 1, 2018. We funded the Hunt Acquisition with borrowings under the Credit Facility. The Hunt Acquisition expands our core 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. As a result of the Hunt Acquisition we are the operator of substantially all of our Eagle Ford acreage.

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 has 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.

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 representing final adjustments for the period from the effective date through the closing date and the curing of title defects for certain properties. As of December 31, 2017, there was $3.2 million remaining in the Escrow Account, which is included as a component of noncurrent "Other assets" on our Consolidated Balance Sheet. Of this total, $2.5 million was transferred as described above and the remaining $0.7 million was distributed to us in February 2018 as well.

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. The Devon Properties include increases in working interests of many properties for which we are the operator as well as other properties that are contiguous to our existing asset base in South Texas.

We incurred a total of $1.3 million of transaction costs associated with the Hunt and Devon Acquisitions during 2017, including advisory, legal, due diligence and other professional fees. These costs have been recognized as a component of our "General and administrative" 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 preliminary fair values assigned to the net assets acquired as of the Date of Acquisition and the consideration transferred:

Assets		
Oil and gas properties - proved	$	42,891
Oil and gas properties - unproved		146,686
Other property and equipment		8,642
Liabilities		
Asset retirement obligations		494
Net assets acquired	$	197,725
Cash consideration paid	$	190,599
Amount transferred to Devon from the Escrow Account on the Date of Acquisition		7,049
Amount due to Devon from the Escrow Account in February 2018		2,506
Application of working capital adjustments, net		(2,429)
Total consideration	$	197,725

The fair values of the oil and gas properties acquired 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.

The results of operations attributable to the Devon Acquisition have been included in our Consolidated Financial Statements for the periods after September 30, 2017. The Devon Acquisition provided revenues and earnings of approximately $9 million and $4 million, respectively, for the period from October 1, 2017 through December 31, 2017. The following table presents unaudited summary pro forma financial information for the year ended December, 31, 2017 assuming the Devon Acquisition 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 Devon Acquisition 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 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.

Total revenues	$	184,831
Net income attributable to common shareholders	$	23,360
Net income per share - basic	$	1.56
Net income per share - diluted	$	1.55

Divestitures

South Texas Properties

In October 2015, we sold certain non-core Eagle Ford properties for $12.5 million net of transaction costs and customary closing adjustments. We recognized a loss of $9.5 million on this transaction.

Mid-Continent Properties

In October 2015, we sold certain properties in Oklahoma that were outside of our core Granite Wash operating region for approximately $0.1 million which represented their approximate carrying values.

East Texas Properties

In August 2015, we sold our Cotton Valley and Haynesville Shale assets in East Texas and received cash proceeds of approximately $73 million, net of transaction costs and customary closing adjustments. The effective date of the sale was May 1, 2015 and we recognized a gain of approximately $43 million. The carrying value of the net assets disposed in this transaction was $29.5 million, including oil and gas properties and other assets of $33.3 million, net of related AROs of $3.8 million. The net pre-tax operating income (loss), excluding the gain on sale and impairment charges, attributable to the East Texas assets was $1.3 million for the year ended December 31, 2015. The net proceeds from this transaction were used to pay down a portion of our outstanding borrowings under the RBL.

6. Accounts Receivable and Major Customers

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

	December 31,	
	2017	2016
Customers	$ 39,106	$ 20,489
Joint interest partners	32,493	7,238
Other	584	3,789
	72,183	31,516
Less: Allowance for doubtful accounts	(2,362)	(2,421)
	$ 69,821	$ 29,095

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 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. For the year ended December 31, 2016, three customers accounted for $122.7 million, or approximately 93% of our consolidated product revenues. The revenues generated from these customers during 2016 were $93.5 million, $15.7 million and $13.5 million, or approximately 71%, 12% and 10% of the consolidated total, respectively. As of December 31, 2016, $16.7 million, or approximately 81% of our consolidated accounts receivable from customers was related to these customers. No significant uncertainties exist related to the collectability of amounts owed to us by any of these customers.

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.

Commodity Derivatives

We typically utilize collars, swaps and swaptions, 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, Light Louisiana Sweet ("LLS") crude oil and NYMEX Henry Hub gas 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.

On May 13, 2016, the Bankruptcy Court approved our motion to enter into new commodity derivative contracts. Accordingly, we hedged a substantial portion of our future crude oil production through the end of 2019, as required in the RSA, at a weighted-average price of approximately $49.12 per barrel. We also entered into additional hedge contracts in 2017 as reflected in the table that follows. We are currently unhedged with respect to natural gas as well as NGL production.

The following table sets forth our commodity derivative positions as of December 31, 2017:

	Instrument [1]	Average Volume Per Day	Weighted Average Price	Fair Value Asset	Fair Value Liability
Crude Oil:		(barrels)	($/barrel)		
First quarter 2018	Swaps	8,013	$ 51.14	$ —	$ 7,622
Second quarter 2018	Swaps	7,984	$ 51.15	—	7,075
Third quarter 2018	Swaps	7,955	$ 51.15	—	6,241
Fourth quarter 2018	Swaps	7,955	$ 51.15	—	5,357
First quarter 2019	Swaps	6,446	$ 50.97	—	3,845
Second quarter 2019	Swaps	6,421	$ 50.97	—	3,336
Third quarter 2019	Swaps	6,397	$ 50.97	—	2,886
Fourth quarter 2019	Swaps	6,398	$ 50.97	—	2,528
First quarter 2020	Swaps	2,000	$ 51.29	—	441
Second quarter 2020	Swaps	2,000	$ 51.29	—	353
Third quarter 2020	Swaps	2,000	$ 51.29	—	283
Fourth quarter 2020	Swaps	2,000	$ 51.29	—	228
Settlements to be paid in subsequent period					1,482

[1] Including the effect of additional hedge contracts entered into in January 2018, we have hedged our crude oil production as follows: 2018 - 6,227 BOPD at a weighted-average WTI-based price of $50.70 per barrel and 2,500 BOPD at a weighted-average LLS-based price of $55.18 per barrel, 2019 - 4,915 BOPD at a weighted-average WTI-based price of $52.12 per barrel and 2,500 BOPD at a weighted-average LLS-based price of $51.30 per barrel and 2020 - 4,000 BOPD at a weighted-average WTI-based price of $ 52.67 per barrel.

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, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Derivative gains (losses)	$ (17,819)	$ (16,622)	$ (8,333)	$ 71,247

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, 2017		December 31, 2016	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ —	$ 27,777	$ —	$ 12,932
Commodity contracts	Derivative assets/liabilities – noncurrent	—	13,900	—	14,437
		$ —	$ 41,677	$ —	$ 27,369

As of December 31, 2017, we reported a commodity derivative liability of $41.7 million. The net and gross amounts for our derivative assets and liabilities are the same for both periods presented above. The contracts associated with this position are with five 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, 2017	December 31, 2016
Oil and gas properties:		
Proved	$ 460,029	$ 251,083
Unproved	117,634	4,719
Total oil and gas properties	577,663	255,802
Other property and equipment	12,712	3,575
Total property and equipment	590,375	259,377
Accumulated depreciation, depletion and amortization	(61,316)	(11,904)
	$ 529,059	$ 247,473

Unproved property costs of $117.6 million and $4.7 million have been excluded from amortization as of December 31, 2017 and December 31, 2016, respectively. We transferred $40.4 million and $3.8 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 year ended December 31, 2017 and Successor period ended December 31, 2016. We capitalized internal costs of $2.4 million and $0.5 million and interest of $2.7 million and less than $0.1 million during the year ended December 31, 2017 and the Successor period ended December 31, 2016, respectively, in accordance with our accounting policies. Average DD&A per barrel of oil equivalent of proved oil and gas properties was $12.87 for the year ended December 31, 2017, $11.21 for the Successor period from September 13, 2016 through December 31, 2016, $10.04 for the Predecessor period from January 1, 2016 through September 12, 2016 and $42.22 for the year ended December 31, 2015. The DD&A rate for the Predecessor periods 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:

	Successor		Predecessor
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016
Balance at beginning of period	$ 2,459	$ 2,687	$ 2,621
Fresh Start Accounting adjustment	—	—	(754)
Changes in estimates	118	27	176
Liabilities incurred	149	—	469
Liabilities settled	(139)	(311)	—
Purchase of properties	494	—	—
Accretion expense	205	56	175
Balance at end of period	$ 3,286	$ 2,459	$ 2,687

10. Long-Term Debt

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

	December 31, 2017		December 31, 2016	
	Principal	Unamortized Discount and Issuance Costs [1]	Principal	Unamortized Discount and Issuance Costs [1]
Credit facility [2]	$ 77,000		$ 25,000	
Second lien term loans	200,000	$ 11,733	—	$ —
Totals	277,000	11,733	25,000	—
Less: Unamortized discount	(3,839)		—	
Less: Unamortized deferred issuance costs	(7,894)		—	
Long-term debt, net	$ 265,267		$ 25,000	

[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. As of March 1, 2018, the Credit Facility provides for a $340.0 million revolving commitment and borrowing base and a $5 million sublimit for the issuance of letters of credit. On March 1, 2018, we entered into the Master Assignment, Agreement and Amendment No. 4 to the Credit Facility (the "Fourth Amendment") whereby the borrowing base was redetermined from $237.5 million to $340.0 million. In the year ended December 31, 2017, we paid and capitalized issue costs of $1.7 million in connection with three separate amendments to the Credit Facility and wrote-off $0.8 million of previously capitalized issue costs due to changes in the composition of financial institutions comprising the Credit Facility bank group associated with those amendments. 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 Spring 2018 redetermination was accelerated to March in connection with the Hunt Acquisition and became effective with the Fourth Amendment. The Credit Facility is available to us to pay expenses associated with our bankruptcy proceedings and for general corporate purposes including working capital. The Credit Facility matures in September 2020. We had $0.8 million in letters of credit outstanding as of December 31, 2017 and December 31, 2016.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate ("LIBOR") plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on LIBOR borrowings is payable every one, three or six months, at the election of the borrower, and is computed on the basis of a year of 360 days. As of December 31, 2017, the actual interest rate on the outstanding borrowings under the Credit Facility was 4.78%. 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, on December 31, 2017 of 3.75 to 1.00 and decreasing on March 31, 2018 and thereafter to 3.50 to 1.00.

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

As of December 31, 2017, 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, 2017, the actual interest rate of outstanding borrowings under the Second Lien Facility was 8.57%. 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, 2017, 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.

Pre-Petition Credit Facility

As described in Note 4, our principal and interest obligations outstanding under the RBL as well as certain associated fees and expenses were satisfied in cash in full on the Emergence Date. These obligations were funded from a combination of cash on hand, proceeds from the Rights Offering and proceeds from initial borrowings under the Credit Facility.

2019 Senior Notes and 2020 Senior Notes

The Senior Notes were included in “Liabilities subject to compromise” on the Consolidated Balance Sheet of the Predecessor as of September 12, 2016 (see Note 4) and were included in “Current liabilities” as of December 31, 2015. As described in Note 4, the Senior Notes were canceled upon our emergence from bankruptcy.

11. Income Taxes

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Current income taxes (benefit)				
Federal	$ —	$ —	$ —	$ (660)
State	—	—	—	1
	—	—	—	(659)
Deferred income taxes (benefit)				
Federal	(4,943)	—	—	(261)
State	—	—	—	(4,451)
	(4,943)	—	—	(4,712)
	$ (4,943)	$ —	$ —	$ (5,371)

The following table reconciles the difference between the income tax 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, 2017		September 13 Through December 31, 2016		January 1 Through September 12, 2016		Year Ended December 31, 2015	
Computed at federal statutory rate	$ 9,701	35.0 %	$ (1,854)	35.0 %	$ 369,111	35.0 %	$ (555,916)	35.0 %
State income taxes, net of federal income tax benefit	(1,383)	(5.0)%	197	(3.7)%	1,989	0.2 %	(4,438)	0.3 %
Change in valuation allowance	(24,353)	(87.8)%	1,657	(31.3)%	(384,692)	(36.5)%	554,879	(35.0)%
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	332	1.2 %	—	— %	20	— %	104	— %
	$ (4,943)	(17.8)%	$ —	— %	$ —	— %	$ (5,371)	0.3 %

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

	December 31, 2017	December 31, 2016
Deferred tax assets:		
Property and equipment	$ 37,345	$ 183,303
Pension and postretirement benefits	452	710
Share-based compensation	435	28
Net operating loss (“NOL”) carryforwards	127,821	87,622
Fair value of derivative instruments	8,752	9,579
Other	7,608	7,166
	182,413	288,408
Less: Valuation allowance	(177,470)	(288,408)
Net deferred tax assets	$ 4,943	$ —

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").

On that same date, the SEC staff also issued Staff Accounting Bulletin No. 118 ("SAB 118"), which provides guidance on accounting for the tax effects of the TCJA. SAB 118 provides a measurement period that should not extend beyond one year from the TCJA enactment date for companies to complete the accounting under the FASB's Accounting Standards Codification ("ASC") 740, *Income Taxes* ("ASC 740"). In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the TCJA for which accounting under ASC 740 is complete. To the extent that a company's accounting for certain income tax effects of the TCJA is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimated in the financial statements. If the Company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the TCJA.

In connection with our initial 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, we anticipate that our existing AMT credit carryovers will become refundable beginning with the 2018 tax year. The AMT credit carryforwards will be 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 full utilization of the AMT credit carryforwards by 2021.

In addition to the aforementioned offsetting items with respect to the reduction in income tax rates, our income tax provision includes 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. The 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 and the deferred tax asset effectively represent a noncurrent receivable of AMT credits to be applied in the future.

As of December 31, 2017, we had federal NOL carryforwards of approximately $385.7 million, which, if not utilized, expire between 2032 and 2037, and state NOL carryforwards of approximately $446.7 million, which expire between 2024 and 2037. Because of the change in ownership provisions of the Tax Reform Act of 1986, use of a portion of our federal and state NOL may be limited in future periods. As of December 31, 2017, we carried a valuation allowance against our federal and state deferred tax assets of $177.5 million. We incurred pre-tax income in 2017 which, when aggregated with the prior two years, resulted in a pre-tax loss for the three year period ended December 31, 2017. 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. Due to the TCJA, we are eligible for a full refund of our AMT credit carryforwards beginning with the tax year ended December 31, 2018. As noted above, the provision for the year ended December 31, 2017 includes a benefit of $4.9 million for deferred tax assets attributable to the AMT carryforwards while the valuation allowance related to other net deferred tax assets remains in full. 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.

We had no liability for unrecognized tax benefits as of December 31, 2017 and 2016. There were no interest and penalty charges recognized during the years ended December 31, 2017, 2016 and 2015. Tax years from 2013 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

12. Exit Activities

During the Predecessor periods, 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 during those periods and required payments to satisfy obligations associated with the underlying commitments. The following summarizes the most significant exit activities.

Reductions in Force

In connection with efforts to reduce our administrative costs, we took certain actions to reduce our total employee headcount. In 2016, we reduced our total employee headcount by 53 employees. 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 in the Eagle Ford, 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. The vendor recovered a portion of the amount in the form of Successor Common Stock.

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. The vendor recovered a portion of the amount in the form of Successor Common Stock.

13. Additional Balance Sheet Detail

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

	December 31,	
	2017	2016
Other current assets:		
Tubular inventory and well materials	$ 5,146	$ 2,125
Prepaid expenses	1,104	903
Other	—	—
	$ 6,250	$ 3,028
Other assets:		
Deferred issuance costs of the Credit Facility	$ 2,857	$ 2,785
Deposit in escrow [1]	3,210	—
Other	2,440	2,544
	$ 8,507	$ 5,329
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 22,579	$ 9,825
Drilling costs	22,389	2,479
Royalties and revenue - related	39,287	26,116
Compensation - related	2,975	2,557
Interest	223	55
Reserve for bankruptcy claims	3,933	3,922
Other	4,795	4,743
	$ 96,181	$ 49,697
Other liabilities:		
Asset retirement obligations	$ 3,286	$ 2,459
Defined benefit pension obligations	971	1,025
Postretirement health care benefit obligations	476	488
Other	100	100
	$ 4,833	$ 4,072

[1] Represents amount remaining in the Escrow Account for the Devon Acquisition which will fully fund the remaining liability due to Devon for the final settlement (see Note 5).

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 long-term debt. 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, 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)	—

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

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one level of the fair value hierarchy to another level. In such instances, the transfer is deemed to have occurred at the beginning of the quarterly period in which the event or change in circumstances that caused the transfer occurred. There were no transfers during any period in the years ended December 31, 2017, 2016 and 2015.

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 and NYMEX Henry Hub gas closing prices as of the end of the reporting periods. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a level 2 input.

Non-Recurring Fair Value Measurements

The most significant non-recurring fair value measurements utilized in the preparation of our 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, 2017, by category, for the next five years and thereafter:

Year	Minimum Rentals	Drilling and Completion	Gathering and Intermediate Transportation	Derivatives	Other Commitments
2018	$ 241	$ 37,907	$ 10,376	$ 27,777	$ 157
2019	78	—	11,702	12,595	50
2020	47	—	12,962	1,305	50
2021	—	—	12,962	—	5
2022	—	—	12,962	—	—
Thereafter	—	—	63,712	—	—
Total	$ 366	$ 37,907	$ 124,676	$ 41,677	$ 262

Rental Commitments

Operating lease rental expense was $1.0 million, $0.2 million, $2.4 million and $7.2 million, for the year ended December 31, 2017, the Successor period from September 13, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through September 12, 2016, and the year ended December 31, 2015, related primarily to field equipment, office equipment and office leases.

Drilling and Completion Commitments

We had contractual commitments for two drilling rigs as of December 31, 2017. One rig began operations in September 2017 and is subject to a six-month commitment through March 2018. The second rig began operations in November 2017 and is also subject to a six-month commitment through May 2018. In December 2017, we entered into a one-year commitment to utilize certain frac services. We also have a one-year purchase commitment for certain proppant materials. Both the frac services and materials commitments are effective January 1, 2018.

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. During 2016, we reduced our reserve for a litigation matter to $0.1 million from $0.9 million due to our dismissal from the subject litigation.

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, 2017, we have recorded AROs of $3.3 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, 2017 and December 31, 2016, 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 has 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 $0.0 million, $0.1 million, less than $0.1 million and $0.4 million as of December 31, 2017, December 31, 2016, September 12, 2016 and December 31, 2015, respectively.

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 304,981 time-vested restricted stock units ("RSUs") and 98,526 performance restricted stock units ("PRSUs") have been granted as of December 31, 2017.

In the Predecessor periods in 2016 and 2015, 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	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Equity-classified awards	$ 3,809	$ 81	$ 1,511	$ 4,540
Liability-classified awards	—	—	(19)	(711)
	$ 3,809	$ 81	$ 1,492	$ 3,829

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.

The fair value of each option award was estimated on the date of grant using the Black-Scholes-Merton option-pricing formula. Expected volatilities were based on historical changes in the market value of our Predecessor common stock. Separate groups of employees that had similar historical exercise behavior were considered separately to estimate expected lives. Options granted had a maximum term of ten years. We based the risk-free interest rate on the U.S. Treasury rate for the week of the grant having a term equal to the expected life of the option.

The ranges for the assumptions used in the Black-Scholes-Merton pricing formula for the Predecessor stock options granted in the year ended December 31, 2015 were as follows:

Expected volatility	64.6% to 69.4%
Dividend yield	0.00% to 0.00%
Expected life	3.5 to 4.6 years
Risk-free interest rate	0.87% to 1.54%

The weighted-average grant-date fair value of options granted during the Predecessor year ended December 31, 2015 was $3.15 per option. There were no options exercised during 2015 and 2016. The total grant-date fair values of stock options that vested in the Predecessor year 2015 was $1.3 million.

In connection with our emergence from bankruptcy, all stock options outstanding as of September 12, 2016 were canceled.

Common Stock

A portion of the compensation paid to certain non-employee members of our Predecessor board of directors was paid in common stock. Each share of common stock granted as compensation vested immediately upon issuance. In 2015 we granted 195,395 shares of common stock to our non-employee directors at a weighted-average grant date fair value of $1.33 per share. No shares were granted to employees or directors during 2017 or the Successor or Predecessor periods in 2016.

In connection with our emergence from bankruptcy, all shares granted to the non-employee members of our Predecessor board of directors as of September 12, 2016 were canceled.

Deferred Common Stock Units

A portion of the compensation paid to certain non-employee members of our Predecessor board of directors was paid in deferred common stock units. Each deferred common stock unit represented one share of common stock, vested immediately upon issuance, and was available to the holder upon termination or retirement from our board of directors. Deferred common stock units awarded to directors received all cash or other dividends we paid on shares of our common stock.

As of December 31, 2015, our Predecessor shareholders' deficit included deferred compensation obligations of $3.4 million and corresponding amounts for treasury stock.

In connection with our emergence from bankruptcy, all deferred common stock units 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 as of January 1, 2017	107,563	$ 23.15
Granted	197,418	48.41
Vested	(35,854)	23.15
Forfeited	(9,137)	51.71
Balance as of December 31, 2017	259,990	$ 41.32

As of December 31, 2017, we had $8.9 million of unrecognized compensation cost attributable to RSUs. We expect that cost to be recognized over a weighted-average period of 1.9 years. The Predecessor total grant-date fair values of RSUs that vested in 2015 was $2.2 million. 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.

The compensation cost of the Predecessor PBRSUs was based on the fair value derived from a Monte Carlo model. The Monte Carlo model is a binomial valuation model that utilizes certain assumptions, including expected volatility, dividend yield, risk-free interest rates and a measure of total shareholder return.

The ranges for the assumptions used in the Monte Carlo model for the Predecessor PBRSUs granted in 2015 are presented as follows:

Expected volatility	66.5% to 97.7%
Dividend yield	0.0% to 0.0%
Risk-free interest rate	0.01% to 1.31%

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. 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 as of January 1, 2017	—	$ —
Granted	98,526	57.81
Forfeited	—	—
Canceled	—	$ —
Balance as of December 31, 2017	98,526	$ 57.81

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 $0.5 million, $0.1 million, $0.5 million and $0.9 million for the year ended December 31, 2017, the Successor period from September 13, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through September 12, 2016, and the year ended December 31, 2015, 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 $0.2 million and $0.1 million are included in the "Accounts payable and accrued expenses" caption on our Consolidated Balance Sheets as of December 31, 2017 and 2016, 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 $0.1 million, less than $0.1 million, less than $0.1 million and $0.1 million for the year ended December 31, 2017, the Successor period from September 13, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through September 12, 2016, and the year ended December 31, 2015, 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 $1.7 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, 2017 and 2016.

18. Impairments

The following table summarizes impairment charges recorded during the periods presented:

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Oil and gas properties	$ —	$ —	$ —	$ 1,396,340
Other – tubular inventory and well materials	—	—	—	1,084
	$ —	$ —	$ —	$ 1,397,424

The following table summarizes the aggregate fair values of the assets described below, by asset category and the classification of inputs within the fair value measurement hierarchy, at the respective dates of impairment:

	Fair Value Measurement	Level 1	Level 2	Level 3
Year Ended December 31, 2015 (Predecessor)				
Long-lived assets held for use	$ 311,886	$ —	$ —	$ 311,886

We recorded no impairment charges during 2017 and 2016. The significant deterioration of commodity prices in 2015, as reflected in the future strip pricing as of December 31, 2015, triggered an impairment of approximately $1.4 billion to our proved and unproved Eagle Ford properties, which required us to reduce their carrying value to a fair value of approximately $312 million. In 2015, we also recorded an impairment charge of $1.1 million attributable to surplus tubular inventory and well materials.

19. Interest Expense

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

	Successor		Predecessor	
	Year Ended December 31, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2016
Interest on borrowings and related fees [1]	$ 6,995	$ 678	$ 36,012	$ 92,490
Accretion of original issue discount [2]	161	—	—	—
Amortization of debt issuance costs [3]	1,961	226	22,189	4,749
Capitalized interest	(2,725)	(25)	(183)	(6,288)
	$ 6,392	$ 879	$ 58,018	$ 90,951

[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).

20. 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, 2017	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Net income (loss)	$ 32,662	$ (5,296)	$ 1,054,602	$ (1,582,961)
Less: Preferred stock dividends [1]	—	—	(5,972)	(22,789)
Net income (loss) attributable to common shareholders – basic and diluted	$ 32,662	$ (5,296)	$ 1,048,630	$ (1,605,750)
Weighted-average shares – basic	14,996	14,992	88,013	73,639
Effect of dilutive securities [2]	67	—	36,074	—
Weighted-average shares – diluted	15,063	14,992	124,087	73,639

[1] Preferred stock dividends were excluded from diluted earnings per share for the year ended December 31, 2015, as the assumed conversion of the outstanding preferred stock would have been anti-dilutive.

[2] 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. For 2015, approximately 30.2 million potentially dilutive securities, including Predecessor Preferred Stock, stock options and 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)

	Successor			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Revenues [1]	$ 34,986	$ 36,282	$ 34,459	$ 54,327
Operating income	$ 11,603	$ 11,441	$ 7,527	$ 21,240
Income (loss) attributable to common shareholders	$ 28,081	$ 21,329	$ (5,947)	$ (10,801)
Income (loss) per share – basic [2]	$ 1.87	$ 1.42	$ (0.40)	$ (0.72)
Income (loss) per share – diluted [2]	$ 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

	Predecessor			Successor	
	First Quarter	Second Quarter	July 1, 2016 Through September 12, 2016	September 13, 2016 Through September 30, 2016	Fourth Quarter
2016					
Revenues [3]	$ 30,497	$ 37,152	$ 26,661	$ 6,349	$ 32,654
Operating income (loss) [4]	$ (12,507)	$ (614)	$ (7,735)	$ 1,137	$ 10,254
Income (loss) attributable to common shareholders [5]	$ (36,625)	$ (64,800)	$ 1,150,055	$ (3,441)	$ (1,855)
Income (loss) per share – basic [2]	$ (0.43)	$ (0.73)	$ 12.88	$ (0.23)	$ (0.12)
Income (loss) per share – diluted [2]	$ (0.43)	$ (0.73)	$ 10.32	$ (0.23)	$ (0.12)
Weighted-average shares outstanding:					
Basic	85,941	89,051	89,292	14,992	14,992
Diluted	85,941	89,051	111,458	14,992	14,992

[1] 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, 217, September 30, 2017 and December 31, 2017, respectively.

[2] 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.

[3] Includes gains (losses) on sales of assets of $(0.2) million, $0.9 million, $0.5 million and less than $(0.1) million during the quarters ended March 31, 2016 and June 30, 2016, the period from July 1, 2016 through September 12, 2016 and the quarter ended December 31, 2016, respectively.

[4] The equity-classified share-based compensation expense included in the operating loss for the Predecessor periods from July 1, 2016 through September 12, 2016, includes an adjustment of $5.3 million to correct for an error that occurred in the reporting of equity-classified share-based compensation expense for the three months ended June 30, 2016. We have assessed the quantitative and qualitative factors with respect to this error as well as the effect of the correcting adjustment being recorded in the Predecessor period from July 1, 2016 through September 12, 2016 and determined that the amount and timing of the adjustment is not material to the Consolidated Financial Statements taken as a whole for any of the subject periods.

[5] Includes reorganization items attributable to our bankruptcy proceedings of $7.4 million (expense) during the quarter ended June 30, 2016 and $1.152 billion (income) during the period from July 1, 2016 through September 12, 2016 (see Note 4).

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 as of December 31, 2017, 2016 and 2015 were prepared by our independent third party engineers, DeGolyer and MacNaughton, Inc. utilizing data compiled by us. Estimates of our proved oil and gas reserves as of December 31, 2014 were prepared by Wright & Company, Inc. DeGolyer and MacNaughton, Inc. and Wright & Company, Inc. are both independent firms 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. and Wright & Company, 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, 2014 (Predecessor)	69,006	19,219	159,265	114,769
Revisions of previous estimates	(34,525)	(8,667)	(46,859)	(51,002)
Extensions and discoveries	2,519	321	1,584	3,105
Production	(4,923)	(1,381)	(9,713)	(7,923)
Sale of reserves in place	(2,615)	(2,288)	(62,124)	(15,258)
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
Proved Developed Reserves:				
December 31, 2015 (Predecessor)	20,188	6,201	37,172	32,585
December 31, 2016 (Successor)	17,734	4,335	24,899	26,219
December 31, 2017 (Successor)	22,412	4,882	27,229	31,832
Proved Undeveloped Reserves:				
December 31, 2015 (Predecessor)	9,274	1,003	4,981	11,106
December 31, 2016 (Successor)	18,877	2,430	11,783	23,271
December 31, 2017 (Successor)	33,417	3,982	20,038	40,740

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

Year Ended December 31, 2017

We had downward revisions of 9.6 MMBOE, substantially all of which are attributable to the Eagle Ford, 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 for the Eagle Ford 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, as measured on the closing date of the transaction, 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) downward 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) downward revisions of 1.3 MMBOE to our proved undeveloped reserves, all of which are located in the Eagle Ford, due to the loss of certain locations resulting from changes in the timing of our development plans and lower EURs, (iii) downward 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) downward 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 primarily to the resumption of our development plans in the Eagle Ford.

Year Ended December 31, 2015

We had downward revisions of 51.0 MMBOE primarily as a result of the following: (i) downward revisions of 45.2 MMBOE due to the removal of proved undeveloped locations that would not be developed within five years primarily in the Eagle Ford, (ii) downward revisions of 2.9 MMBOE attributable to certain proved wells in the Eagle Ford and (iii) downward revisions of 2.5 MMBOE due to well performance issues, primarily in the Granite Wash in Oklahoma. We added 3.1 MMBOE due primarily to the drilling of 61 gross (38.6 net) wells and the addition of proved undeveloped locations in the Eagle Ford. We sold our Cotton Valley and Haynesville Shale assets in East Texas as well as certain non-core Eagle Ford wells resulting in a decrease of 15.3 MMBOE.

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:

	Successor		Predecessor	
	December 31,		September 12,	December 31,
	2017	2016	2016	2015
Oil and gas properties:				
Proved	$ 460,029	$ 251,083	$ 241,597	$ 2,678,415
Unproved	117,634	4,719	8,338	6,881
Total oil and gas properties	577,663	255,802	249,935	2,685,296
Other property and equipment	10,057	1,230	1,229	11,330
Total capitalized costs relating to oil and gas producing activities	587,720	257,032	251,164	2,696,626
Accumulated depreciation and depletion	(60,247)	(11,669)	—	(2,354,405)
Net capitalized costs relating to oil and gas producing activities [1]	$ 527,473	$ 245,363	$ 251,164	$ 342,221

[1] Excludes property and equipment attributable to our corporate operations which is comprised of certain capitalized hardware, software 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	January 1	
	Year Ended	Through	Through	Year Ended
	December 31,	December 31,	September 12,	December 31,
	2017	2016	2016	2015
Development and other costs [1]	$ 132,969	$ 4,887	$ 4,129	$ 294,445
Proved property acquisition costs [2]	42,397	—	—	—
Unproved property acquisition costs [3]	151,180	—	—	16,052
Exploration costs [4]	696	567	8,311	939
Total costs incurred [5]	$ 327,242	$ 5,454	$ 12,440	$ 311,436

[1] Does not include non-cash ARO assets of $0.3 million, $.0.1 million, $0.6 million and $0.3 million that were added to capitalized costs relating to oil and gas producing activities during the year ended December 31, 2017, the Successor period ended December 31, 2016, the Predecessor period ended September 12, 2016 and the year ended December 31, 2015, respectively.

[2] Represents costs for proved properties acquired in the Devon Acquisition excluding acquired non-cash ARO assets of $0.5 million.

[3] Includes costs for unproved properties acquired in the Devon Acquisition of $146.7 million.

[4] Includes geological and geophysical costs and delay rentals of $0.7 million for the year ended December 31, 2017, $0.6 million for the Successor period ended December 31, 2016, less than $0.1 million for the Predecessor period ended September 12, 2016 and $0.9 million during the year ended December 31, 2015, respectively. Also includes drilling rig termination charges of $1.7 million and $5.9 million during the Predecessor period ended September 12, 2016 and the year ended December 31, 2015, respectively, a $2.0 million charge for failure to complete a drilling carry commitment, a $0.6 million charge for unutilized coiled tubing services and 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.

[5] Excludes capitalized interest of $2.7 million, less than $0.1 million, $0.2 million and $6.3 million during the year ended December 31, 2017, the Successor period ended December 31, 2016, the Predecessor period ended September 12, 2016 and the year ended December 31, 2015, respectively. Also excludes $2.4 million and $0.5 million of capitalized internal costs for the year ended December 31, 2017 and the Successor period ended December 31, 2016, respectively, during which periods we applied the full cost method. We did not capitalize such internal costs while we applied the successful efforts method during the Predecessor periods.

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, 2015 [1]	$ 50.28	$ 14.44	$ 2.70
As of December 31, 2016 [1]	$ 42.75	$ 12.33	$ 2.48
As of December 31, 2017 [1]	$ 51.34	$ 18.48	$ 2.98

[1] Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu. The representative prices of crude oil and natural gas as adjusted for basis differentials and product quality were as follows: Crude oil - $50.06, $40.97 and $45.78 each per barrel. NGLs - $18.02, $11.82 and $13.15 each per barrel and Natural gas - $2.89, $2.40 and $2.59 each per MMBtu, as of December 31, 2017, 2016 and 2015, respectively. NGL prices were estimated as a percentage of the base crude oil price.

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,		
	2017	2016	2015
Future cash inflows	$ 3,091,366	$ 1,667,971	$ 1,557,246
Future production costs	(1,069,910)	(673,538)	(731,951)
Future development costs	(689,998)	(327,213)	(206,616)
Future net cash flows before income tax	1,331,458	667,220	618,679
Future income tax expense	(84,350)	—	—
Future net cash flows	1,247,108	667,220	618,679
10% annual discount for estimated timing of cash flows	(656,624)	(349,670)	(295,368)
Standardized measure of discounted future net cash flows	$ 590,484	$ 317,550	$ 323,311

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,		
	2017	2016	2015
Sales of oil and gas, net of production costs	$ (118,137)	$ (89,080)	$ (180,455)
Net changes in prices and production costs	170,488	(11,971)	(1,442,919)
Changes in future development costs	30,692	59,266	1,376,226
Extensions and discoveries	131,060	35,321	19,396
Development costs incurred during the period	74,880	6,775	222,612
Revisions of previous quantity estimates	(122,357)	(38,151)	(436,898)
Purchases of reserves-in-place	80,878	—	—
Sale of reserves-in-place	—	—	(86,662)
Changes in production rates	12,161	(252)	(767,689)
Accretion of discount	31,755	32,331	147,245
Net change in income taxes	(18,486)	—	290,010
Net increase (decrease)	272,934	(5,761)	(859,134)
Beginning of year	317,550	323,311	1,182,445
End of year	$ 590,484	$ 317,550	$ 323,311

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, 2017. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported 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, 2017, 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, 2017. 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, 2017, 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, 2017, 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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13 Certain Relationships and Related Transactions, and Director Independence

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14 Principal Accountant Fees and Services

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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 58 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).
(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).
(10.2)	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.
(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).
(10.10)	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).
(10.11)*	Hartman Employment Agreement dated May 9, 2016 (incorporated by reference to Exhibit 10.4 to Registrant 's Current Report on Form 8-K filed on May 13, 2016).
(10.12)*	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).
(10.12.1)*	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).
(10.12.2)*	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).
(10.12.3)*	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).
(10.12.4)*	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).
(10.13)	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 KPMG LLP.
(23.3) #	Consent of DeGolyer and MacNaughton.
(23.4) #	Consent of Wright & Company, Inc.
(31.1) #	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2) #	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1) †	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2) †	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(99.1) #	Report of DeGolyer and MacNaughton dated February 9, 2018 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.
† 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)

March 2, 2018

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)	March 2, 2018
/s/ STEVEN A. HARTMAN **Steven A. Hartman**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2018
/s/ TAMMY L. HINKLE **Tammy L. Hinkle**	Vice President and Controller (Principal Accounting Officer)	March 2, 2018
/s/ DAVID GEENBERG **David Geenberg**	Co-Chairman of the Board	March 2, 2018
/s/ MICHAEL HANNA **Michael Hanna**	Director	March 2, 2018
/s/ DARIN G. HOLDERNESS **Darin G. Holderness**	Co-Chairman of the Board	March 2, 2018
/s/ MARC MCCARTHY **Marc McCarthy**	Director	March 2, 2018
/s/ JERRY R. SCHUYLER **Jerry R. Schuyler**	Director	March 2, 2018

Exhibit 10.8

Execution Version

PURCHASE AND SALE AGREEMENT

BETWEEN

HUNT OIL COMPANY

AS SELLER

AND

PENN VIRGINIA OIL & GAS, L.P.

AS PURCHASER

Executed on December 30, 2017

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

<u>EXHIBITS AND SCHEDULES</u>

Exhibit A	Leases
Exhibit A-1	Properties
Exhibit A-2	Certain Equipment
Exhibit A-3	Excluded Assets
Exhibit A-4	Designated Area
Exhibit B	Conveyance
Exhibit C	Persons with Knowledge
Exhibit D	Escrow Agreement
Exhibit E	Transition Services Agreement
Exhibit F	Exploration Wells
Exhibit G	Purchaser Operated Property Costs
Schedule 1.2(d)	Contracts
Schedule 1.2(e)	Surface Contracts
Schedule 1.3(h)	Excluded Permits
Schedule 2.3	Allocated Value
Schedule 3.3(l)	Other Permitted Encumbrances
Schedule 5.7	Litigation
Schedule 5.8	Taxes and Assessments
Schedule 5.9	Outstanding Capital Commitments
Schedule 5.10	Compliance With Laws
Schedule 5.11(a)	Defaults
Schedule 5.11(b)	Material Contracts
Schedule 5.12	Payments For Production
Schedule 5.13	Governmental Authorizations
Schedule 5.14	Preferential Rights & Consents to Assign
Schedule 5.15	Environmental Laws
Schedule 5.16	Leases
Schedule 5.17	Wells
Schedule 5.18	Suspense Funds
Schedule 5.19	Imbalances
Schedule 7.4	Operatorship
Schedule 7.5	Operation of Business
Schedule 7.13(a)	Governmental Bonds
Schedule 7.13(b)	Guarantees
Schedule 9.4(c)	Seller’s Wiring Instructions

PURCHASE AND SALE AGREEMENT

This Purchase and Sale Agreement (the "**Agreement**"), is executed on December 30, 2017 (the "**Execution Date**"), by and between Hunt Oil Company, a Delaware corporation ("**Seller**"), and Penn Virginia Oil & Gas, L.P., a Texas limited partnership ("**Purchaser**"). Seller and Purchaser may each be referred to herein as a "**Party**" and collectively as the "**Parties**."

RECITALS:

WHEREAS, Seller desires to sell to Purchaser and Purchaser desires to purchase from Seller the Assets, in the manner and upon the terms and conditions hereafter set forth.

NOW, THEREFORE, in consideration of the premises and of the mutual promises, representations, warranties, covenants, conditions and agreements contained herein, and for other valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties, intending to be legally bound by the terms hereof, agree as follows:

ARTICLE 1

PURCHASE AND SALE

Section 1.1 **Purchase and Sale**. At the Closing, and upon the terms and subject to the conditions of this Agreement, Seller agrees to sell and convey to Purchaser and Purchaser agrees to purchase, accept and pay for the Assets and assume the Assumed Obligations. Capitalized terms used herein shall have the respective meanings ascribed to them in this Agreement and the capitalized terms used herein and not otherwise defined shall have the meanings set forth in Article 13 hereof.

Section 1.2 **Assets**. As used herein, the term "**Assets**" means, subject to the terms and conditions of this Agreement, all of Seller's right, title, interest and estate, real or personal, recorded or unrecorded, movable or immovable, tangible or intangible, in and to the following, excluding, however, the Excluded Assets:

(a) All of the oil and gas leases, oil, gas and mineral leases, subleases and other leaseholds, carried interests, net profits interests, mineral fee interests, overriding royalty interests, reversionary rights, farmout rights, options, and other similar properties and interests, in each case, to the extent located in (and/or to the extent applying to properties located in) the Designated Area, including those described on Exhibit A (collectively, the "**Leases**"), together with each and every kind and character of right, title, claim, and interest that Seller has in and to the Leases, the lands, currently or previously, covered by the Leases or the lands, currently or previously, pooled, unitized, communitized or consolidated therewith (such lands, currently or previously, covered by the Leases or pooled, unitized, communitized or consolidated therewith being hereinafter referred to as the "**Lands**");

(b) All oil, gas, water, CO_2 or injection wells located on or within the geographical boundaries of the Lands, whether producing, shut-in, plugged or abandoned, and including the wells shown on Exhibit A-1 attached hereto (the "**Wells**");

(c) Any pools or units which include any portion of the Lands or all or a part of any Leases, including those pools or units referred to on Exhibit A-1 (the "**Units**," such Units together with the Leases, Lands and Wells, or in cases when there is no Unit, the Leases together with the Lands and Wells, being hereinafter referred to collectively as the "**Properties**" and individually as a "**Property**"), and including all interests of Seller in Hydrocarbon production from any such Unit, whether such Unit Hydrocarbon production comes from Wells located on or off of a Lease, and all tenements, hereditaments and appurtenances belonging to the Leases and Units;

(d) All contracts, agreements and instruments by which the Properties are bound, or that relate to or are otherwise applicable to the Properties, but in each case only to the extent applicable to the Properties and not other properties of Seller not included in the Assets, including operating agreements, unitization, pooling and communitization agreements, declarations and orders, joint venture agreements, farmin and farmout agreements, water rights agreements, exploration agreements, area of mutual interest agreements, participation agreements, exchange agreements, transportation or gathering agreements, agreements for the sale and purchase of Hydrocarbons and processing agreements, and further including those agreements and instruments identified on Schedule 1.2(d) (hereinafter collectively referred to as the "**Contracts**"); provided that "Contracts" shall exclude (i) any master service agreements, (ii) any contracts, agreements and instruments to the extent transfer is (A) restricted by their respective terms or Third Party agreement and the Required Consents to transfer are not obtained pursuant to Section 3.5, or (B) subject to payment of a fee or other consideration under any license agreement or other agreement with a Person other than an Affiliate of Seller, and for which no consent to transfer has been received or for which Purchaser has not agreed in writing to pay the fee or other consideration, as applicable, and (iii) the instruments constituting the Leases, Surface Contracts and the assignments or conveyances in Seller's chain of title to the Leases or Surface Contracts;

(e) All easements, permits, licenses, servitudes, rights-of-way, surface leases and other surface rights appurtenant to, and used or held for use primarily in connection with, the Properties, including those identified on Schedule 1.2(e) (hereinafter collectively referred to as the "**Surface Contracts**"); provided that "Surface Contracts" shall exclude any permits and other appurtenances to the extent transfer is (i) restricted by their respective terms or Third Party agreement and the Required Consents to transfer are not obtained pursuant to Section 3.5, or (ii) subject to payment of a fee or other consideration under any license agreement or other agreement with a Person other than an Affiliate of Seller, and for which no consent to transfer has been received or for which Purchaser has not agreed in writing to pay the fee or other consideration, as applicable;

(f) (i) All equipment, machinery, fixtures and other tangible personal property and improvements located on the Properties and used or held for use primarily in connection with the operation of the Properties, including any wells, tanks, boilers, buildings, fixtures, injection facilities, saltwater disposal facilities, compression facilities, pumping units and engines, flow lines, gas and oil treating facilities, machinery, power lines, telephone and telegraph lines, SCADA and well communication devices, roads, and other appurtenances, improvements and facilities, and (ii) the items expressly identified on Exhibit A-2, whether such items identified on Exhibit A-2 are located on or off the Properties (collectively, the "**Equipment**");

(g) all pipelines and gathering systems located at, on, or under any of the Lands (collectively, the "**Pipeline Systems**");

(h) All Hydrocarbons produced from or attributable to the Properties from and after the Effective Time and all inventories of Hydrocarbons produced from or attributable to the Properties that are in storage in tanks or pipelines on the Effective Time only to the extent that Seller receives an upward adjustment to the Purchase Price pursuant to Section 2.2(a)(ix) in respect of such Hydrocarbons;

(i) All Imbalances; and

(j) All lease files, land files, well files, facility records, gas and oil sales contract files, gas processing files, division order files, abstracts, title files, title opinions (and all related curative files), land surveys, logs, maps (including any shape files, plats, and records relating to the Pipeline Systems), engineering data and reports, Contract files, and all other books, records, data, files, maps, and accounting records to the extent related to the Assets, or to the extent used or held for use in connection with the ownership, maintenance or operation thereof, but excluding (i) any books, records, data, files, maps and accounting records to the extent disclosure or transfer is restricted by Third Party agreement or applicable Law and the Required Consents to transfer are not obtained pursuant to Section 3.5, or subjected to payment of a fee or other consideration by any license agreement or other agreement with a Person other than an Affiliate of Seller, or by applicable Law, and for which no consent to transfer has been received or for which Purchaser has not agreed in writing to pay the fee or other consideration, as applicable; (ii) computer software; (iii) all legal records and legal files of Seller (and work product of Seller's legal counsel and records), to the extent protected by attorney-client privilege, but excluding in each case Leases, Contracts, Surface Contracts and title opinions; (iv) records relating to the offer, negotiation or consummation of the sale by Seller of the Assets or any interest in the Properties; and (v) Seller's reserve studies, estimates and evaluations, and engineering studies and economic studies (such copies, collectively, and subject to such exclusions, the "**Records**"); provided, however, that Seller may retain the originals of such Records (A) as Seller has determined may be required for litigation, Tax, accounting, and auditing purposes (provided that Seller shall provide Purchaser copies of such Records) or (B) in instances in which the Records for the Assets are commingled with records for properties not included in the Assets (the "**Retained Records**") and shall provide Purchaser with access to such Retained Records in accordance with Section 1.5(c).

Section 1.3 **Excluded Assets**. Notwithstanding the foregoing, the Assets shall not include, and there is excepted, reserved and excluded from the purchase and sale contemplated hereby (collectively, the "**Excluded Assets**"):

(a) (i) All corporate, partnership, limited liability company, financial, tax and legal records of Seller that relate to Seller's business generally (whether or not relating to the Assets), (ii) all books, records and files that relate to the Excluded Assets, (iii) those records retained by Seller pursuant to Section 1.2(j) and (iv) copies of any other records retained by Seller pursuant to Section 1.5;

(b) The items expressly identified on Exhibit A-3;

(c) All claims for refunds (whether by way of refund, credit, offset or otherwise) of, credits attributable to or rights to receive funds from any Governmental Body or loss carry forwards with respect to (i) Asset Taxes attributable to the Assets for any taxable period, or portion thereof, ending at or prior to the Effective Time or to Seller's businesses generally, (ii) Income Taxes of Seller (or Seller's Affiliates or its direct or indirect owners), or (iii) any Taxes attributable to the Excluded Assets;

(d) All rights to any other costs or expenses borne by Seller or Seller's predecessors in interest and title attributable to periods prior to the Effective Time except to the extent such rights arise from or by their terms cover obligations or liabilities assumed by Purchaser hereunder;

(e) All rights relating to existing claims and causes of action (including insurance claims, whether or not asserted, under policies of insurance or claims to the proceeds of insurance) that may be asserted against a Third Party, except those described in Schedule 5.7 hereto and except to the extent such rights and claims and causes of action arise from or by their terms cover obligations or liabilities assumed by Purchaser hereunder;

(f) All rights of Seller under Contracts attributable to periods before the Effective Time insofar as such rights relate to Seller Indemnity Obligations or other liabilities of Seller retained under this Agreement;

(g) Rights to initiate and conduct joint interest audits or other audits of Property Costs incurred before the Effective Time, and to receive costs and revenues in connection with such audits, in each case to the extent Seller is responsible for such Property Costs under this Agreement;

(h) Seller's bonds, permits and licenses used in the conduct of Seller's business generally including as reflected in Schedule 1.3(h);

(i) All trade credits, account receivables, note receivables, take-or-pay amounts receivable, and other receivables attributable to the Assets (excluding Hydrocarbon inventories subject to Section 1.2(h) for which Seller receives an upward adjustment to the Purchase Price) with respect to any period of time prior to the Effective Time, as determined in accordance with GAAP, except to the extent that they arise from or by their terms cover obligations or liabilities assumed by Purchaser hereunder;

(j) all Intellectual Property of Seller;

(k) Bonds, letters of credit and guarantees retained by Seller pursuant to Section 7.13;

(l) All vehicles used in connection with the Assets;

(m) All tools, pulling machines, warehouse stock, equipment or material temporarily located on the Properties and not used or held for use in the operation of the Properties as currently operated expressly identified on Exhibit A-3;

(n) All hedges, futures, swaps and other derivatives, including rights relating thereto, affecting the Assets;

(o) All computers, phones, office supplies, furniture and related personal effects located off the Properties or only temporarily located on the Properties;

(p) All buildings, offices, office leases, improvements, appurtenances, field offices and yards not located on the Properties;

(q) Assets retained by Seller or excluded from the Assets at Closing pursuant to this Agreement, including pursuant to Sections 3.4(d)(ii), 3.5, 4.4(a)(ii) or 7.7, subject to the terms of such Sections;

(r) The G & G Data; and

(s) All leased personal property (including leased vehicles) expressly identified on Exhibit A-3.

Section 1.4 **Effective Time; Proration of Revenues** .

(a) Possession of the Assets shall be transferred from Seller to Purchaser at the Closing, but certain financial benefits and obligations of the Assets shall be transferred effective as of 12:01 A.M., local time, where the respective Assets are located, on October 1, 2017 (the "**Effective Time**"), as further set forth in this Agreement.

(b) Except to the extent accounted for (or otherwise set forth) in the adjustments to the Purchase Price made under Section 2.2, (i) Purchaser shall be entitled to all production from or attributable to the Properties at and after the Effective Time (and all products and proceeds attributable thereto), and to all other income, proceeds, receipts and credits earned with respect to the Assets at or after the Effective Time and (ii) Seller shall be entitled to all production from or attributable to the Properties prior to the Effective Time (and all products and proceeds attributable thereto), and to all other income, proceeds, receipts and credits earned with respect to the Assets prior to the Effective Time. Seller shall be responsible for all Property Costs attributable to the Seller Operated Assets incurred prior to the Effective Time and the Purchaser Operated Property Costs, in both cases solely for the purposes of the determination of the Adjusted Purchase Price pursuant to Section 2.2. The terms "earned" and "incurred," as used in this Agreement, shall be interpreted in accordance with GAAP and Council of Petroleum Accountants Society ("**COPAS**") standards, as implemented by

Seller in the ordinary course of business consistent with past practice. For purposes of allocating production (and accounts receivable with respect thereto), under this Section 1.4(b), (x) liquid Hydrocarbons shall be deemed to be "from or attributable to" the Leases, Units and Wells when they pass through the pipeline connecting into the storage facilities into which they are transported from the lands covered by the applicable Lease, Unit or Well, or if there are no storage facilities, when they pass through the LACT meter or similar meter at the entry point into the pipelines through which they are transported from such lands and (y) gaseous Hydrocarbons shall be deemed to be "from or attributable to" the Leases, Units and Wells when they pass through the delivery point sales meters or similar meters at the entry point into the pipelines through which they are transported from such lands. Seller shall utilize reasonable interpolative procedures to arrive at an allocation of production when exact meter readings or gauging and strapping data is not available.

Section 1.5 **Delivery and Maintenance of Records and Retained Records**.

(a) Seller, at Purchaser's cost, shall use reasonable efforts to deliver the Records in Seller's possession or control (FOB Seller's office), to Purchaser within twenty (20) Business Days following Closing. Seller may retain originals of the Retained Records and/or copies of any Records.

(b) Purchaser, for a period of five (5) years following the Closing, will (i) retain the Records, (ii) provide Seller, its Affiliates, and its and their officers, employees and representatives with access to the Records during normal business hours for review and copying at Seller's expense and (iii) provide Seller, its Affiliates, and its and their officers, employees and legal counsel with access, during normal business hours, to materials received or produced after Closing relating to any claim for indemnification made under Section 11.2 of this Agreement (excluding, however, any materials constituting attorney work product, materials subject to attorney-client privilege or other applicable immunity of disclosure, and all information subject to an applicable confidentiality restriction in favor of third parties) for review and copying at Seller's expense; provided, however, that Seller provides reasonable advance notice that Seller wishes to access such Records and/or other materials described in clauses (ii) and (iii) of this sentence; provided further, that the Records and/or other materials described in clause (iii) above (x) shall be subject to the confidentiality restrictions set forth in the Confidentiality Agreement, (y) shall not constitute an admission that any such materials are relevant to any given indemnity claim, and (z) (1) any inadvertent disclosure by Purchaser of materials subject to confidentiality restrictions, attorney-client privilege or other immunity of disclosure or constituting attorney work product shall not constitute a waiver of the applicable privilege or protection and (2) notwithstanding any such inadvertent disclosure, Purchaser shall retain the right to assert all applicable privileges and protections, and Seller, its Affiliates, and its and their officers, employees and representatives shall be prohibited from using the inadvertently disclosed materials for any purpose. At the end of such five-year period, Purchaser shall provide Seller a reasonable opportunity, at Seller's expense, to copy any or all of such Records.

(c) Seller, for a period of five (5) years following the Closing, will (i) retain the Retained Records, (ii) provide Purchaser, its Affiliates, and its and their officers, employees and representatives with access to the Retained Records during normal business hours for review and copying at Purchaser's expense and (iii) provide Purchaser, its Affiliates, and its and their officers, employees and legal counsel with access, during normal business hours, to materials received or produced after Closing relating to any claim for indemnification made under Section 11.2 of this Agreement (excluding, however, any materials constituting attorney work product, materials subject to attorney-client privilege or other applicable immunity of disclosure, and all information subject to an applicable confidentiality restriction in favor of third parties) for review and copying at Purchaser's expense and to Purchaser's and its Affiliates' employees for the purpose of discussing any such claim; provided, however, that Purchaser provides reasonable advance notice that Purchaser wishes to access such Records and/or other materials described in clauses (ii) and (iii) of this sentence; provided further, that the Retained Records and the information contained therein and the Records and/or other materials described in clause (iii) above (x) shall be subject to the confidentiality restrictions set forth in the Confidentiality Agreement, (y) shall not constitute an admission that any such materials are relevant to any given indemnity claim, and (z) (1) any inadvertent disclosure by Seller of materials subject to confidentiality restrictions, attorney-client privilege or other immunity of disclosure or constituting attorney work product shall not constitute a waiver of the applicable privilege or protection and (2) notwithstanding any such inadvertent disclosure, Seller shall retain the right to assert all applicable privileges and protections, and Purchaser, its Affiliates, and its and their officers, employees and representatives shall be prohibited from using the inadvertently disclosed materials for any purpose. At the end of such five-year period, Seller shall provide Purchaser a reasonable opportunity, at Purchaser's expense, to copy any or all of such Records.

ARTICLE 2

PURCHASE PRICE

Section 2.1 **Purchase Price**. The purchase price for the Assets (the "**Purchase Price**") shall be **$86,000,000**, and shall be adjusted as provided in Section 2.2 (as adjusted, the "**Adjusted Purchase Price**").

Section 2.2 **Adjustments to Purchase Price**.

(a) The Purchase Price for the Assets shall be adjusted as follows with all such amounts being determined in accordance with GAAP and COPAS standards (with such adjustments being made so as to not give duplicative effect):

(i) Reduced by the aggregate amount of the following: (A) proceeds received and retained by Seller from the sale of Hydrocarbons (net of any royalties, overriding royalties or other burdens on or payable out of production, gathering, processing and transportation costs) produced from (I) the Properties (except for the Exploration Wells) after the Effective Time and (II) the Exploration Wells whether on, prior or after the Effective Time; and (B) all Property Costs attributable to the

Seller Operated Assets (excluding the Property Costs described in Section 2.2(a)(xi)) that are paid by Purchaser or its Affiliates and incurred with respect to any period prior to the Effective Time;

(ii) Reduced by the Purchaser Operated Property Costs;

(iii) Reduced in accordance with Section 3.5, by an amount equal to the Allocated Value of those Properties with respect to which Preferential Rights have been exercised prior to Closing;

(iv) Reduced in accordance with Section 7.7 by an amount equal to the Allocated Value of those Properties that are subject to a suit, action or proceeding prior to Closing seeking to restrain, enjoin or otherwise prohibit the consummation of the transactions contemplated hereby in connection with a claim to enforce preferential rights;

(v) Subject to Section 3.4(i), reduced by the applicable Title Defect Amount as a result of Title Defects for which the Title Defect Amount has been finally determined or agreed pursuant to Section 3.4 (or, for purposes of the Closing Payment, pursuant to Purchaser's good faith estimate set forth in a timely delivered Title Defect Notice), and by the Allocated Value of any Title Defect Property retained by Seller pursuant to Section 3.4(d)(ii), less the applicable Title Benefit Amount as a result of Title Benefits for which the Title Benefit Amount has been finally determined or agreed pursuant to Section 3.4;

(vi) Reduced by the Allocated Values of any Properties excluded by Seller pursuant to Section 3.6;

(vii) Reduced by (A) subject to Section 4.4, any amounts pursuant to Section 4.4(a) regarding Environmental Liabilities for any affected Property not retained by Seller, and (B) the Allocated Value of any Property retained by Seller pursuant to Section 4.4(a)(ii);

(viii) Reduced by the amount of all Asset Taxes allocated to Seller in accordance with Section 7.8(a) but paid or otherwise economically borne by Purchaser;

(ix) Increased by the amount equal to the value of all of Seller's inventories of Hydrocarbons produced from or attributable to the Properties (other than the Exploration Wells) that are in storage above the load line or pipeline connection, as applicable, as of the Effective Time (which value shall be computed using the applicable contract price at the Effective Time), less any applicable royalties and similar burdens; provided, however, that the adjustment contemplated by this paragraph shall only be made to the extent that Seller does not receive and retain the proceeds, or portion thereof, attributable to the sale of such Hydrocarbons;

(x) Increased by the amount of all Property Costs (but excluding any costs or expenses attributable to the Exploration Wells) that are paid by Seller and incurred on or after the Effective Time (or with respect to any period on or after the Effective Time), except any Property Costs and other such costs already deducted in the determination of proceeds in Section 2.2(a)(i);

(xi) Increased by the amount of all Property Costs that are paid by Seller with respect to the Exploration Wells, whether incurred on, before or after the Effective Time, except any costs and expenses already deducted in the determination of proceeds in Section 2.2(a)(i) or taken into account in Section 2.2(a)(x);

(xii) Increased by the amount of all Asset Taxes allocated to Purchaser in accordance with Section 7.8(a) but paid or otherwise economically borne by Seller;

(xiii) Increased by an amount equal to the value, as determined according to the COPAS 2005 Accounting Procedures, of all surplus tubular, goods and physical inventory to the extent such items are owned by Seller, included in the Assets at the Effective Time, and specifically identified as such on Exhibit A-2;

(xiv) Increased by an overhead charge of **$29,000** per month (pro-rated for any partial months as applicable) for the period of time beginning at the Effective Time and ending on the Closing Date;

(xv) Decreased by the amount of any Suspended Proceeds, in accordance with Section 7.10, as applicable;

(xvi) Increased or decreased, as the case may be, by an amount equal to the aggregate amount of Imbalances set forth on Schedule 5.19 multiplied by **$2.70** per MMBtu; and

(xvii) Increased or decreased, as the case may be, by any other amount provided for in this Agreement.

(b) Neither Party shall have any separate rights to receive any production or income, proceeds, receipts and credits with respect to which an adjustment has been made pursuant to Section 2.2(a).

(c) For the purposes of calculating the adjustments to the Purchase Price under this Section 2.2 or implementing the terms of Section 7.8 or Article 11, (i) right-of-way fees, insurance premiums and Property Costs (excluding Taxes which are addressed in clauses (ii), (iii), and (iv) of this sentence), delay rentals, lease bonuses, minimum royalties, option payments, lease extension payments and shut-in royalties that are paid periodically shall be prorated based on the number of days in the applicable period falling before, or at and after, the Effective Time, (ii) ad valorem, property, severance, production or similar Taxes which are based on the quantity of or the value of production of Hydrocarbons shall be apportioned between Seller and Purchaser based on the number of units or value of production actually produced, as applicable, before, and after, the Effective Time, (iii) other ad valorem, property, severance, production or similar Taxes shall be prorated based on the number of days in the applicable period falling before, or at and after, the Effective Time, and (iv) all other Taxes shall be apportioned based on an interim closing of the books of Seller as of the Effective Time.

Section 2.3 **Allocation of Purchase Price**.

(a) For the purposes of determining the value of any Assets in connection with any Title Defect, Title Benefit, Environmental Liability, Preferential Rights, Required Consents, breach of the Special Warranty and/or the exclusion of any Asset from the transaction pursuant to the terms of this Agreement, concurrent with the execution of this Agreement, Purchaser and Seller have agreed upon an allocation of the unadjusted Purchase Price among the Units on Schedule 2.3. The "**Allocated Value**" for any such Unit or Well equals the portion of the unadjusted Purchase Price allocated to such Unit or Well on Schedule 2.3, increased or decreased as described in Section 2.2.

(b) For federal income tax purposes, Purchaser and Seller shall use commercially reasonable efforts to agree on an allocation of the Purchase Price in a manner consistent with the Allocated Values within thirty (30) days after the determination of the Adjusted Purchase Price. If the Parties reach an agreement with respect to the allocation of the Purchase Price under this subsection, Seller and Purchaser agree (i) that the agreed allocation shall be used by Seller and Purchaser as the basis for reporting asset values and other items for purposes of all federal, state, and local Tax Returns, including Internal Revenue Service Form 8594 and (ii) that, except as required by applicable Law, neither they nor their Affiliates will take positions inconsistent with the agreed allocation in any Tax Returns, in notices to Governmental Bodies, in audit or other proceedings with respect to Taxes, in notices to preferential purchase right holders, or in other documents or notices relating to the transactions contemplated by this Agreement without the consent of the other Party. Each Party shall promptly notify the other Party in writing upon receipt of notice of any pending or threatened Tax audit or assessment challenging the agreed allocation, and neither Party shall agree to any proposed adjustment to the agreed allocation by any Governmental Body without first giving to the other Party prior written notice. However, nothing contained herein shall prevent either Party from settling any proposed deficiency or adjustment by any Governmental Body based upon or arising out of the agreed allocation, and neither Party shall be required to litigate any proposed deficiency or adjustment by any Governmental Body challenging such agreed allocation. If the Parties are unable to reach agreement within thirty (30) days after the determination of the Adjusted Purchase Price, then each Party shall be entitled to adopt its own position regarding the allocation of Purchase Price under this subsection; provided that such position shall, to the extent allowed under applicable federal income tax Law, be consistent with the Allocated Values.

Section 2.4 **Deposit**. Within two (2) Business Days of the Execution Date, Purchaser will deliver to the Escrow Agent an earnest money deposit in an amount equal to **5%** of the Purchase Price (the " **Deposit**"), to be held in an escrow account (the "**Escrow Account**") pursuant to the

Escrow Agreement. The Deposit shall be non-interest bearing and applied against the Purchase Price if the Closing occurs or otherwise shall be distributed in accordance with Section 10.3.

ARTICLE 3

TITLE MATTERS

Section 3.1 **Seller's Title**.

(a) This Article 3 and the Special Warranty in the Conveyance (subject to Article 11) shall, to the fullest extent permitted by applicable Law, be the exclusive right and remedy of Purchaser with respect to title to the Assets.

(b) The conveyance of the Assets to be delivered by Seller to Purchaser shall be substantially in the form of Exhibit B (the "**Conveyance**").

(c) For purposes of Article 3 and Article 4, references to "Units" shall be to the Units set forth on Schedule 2.3.

Section 3.2 **Certain Definitions**.

(a) As used in this Agreement, the term " **Defensible Title**" means that title (whether record, contractual or otherwise) of Seller to a Unit that can be successfully defended if challenged, as of the Effective Time and the Closing Date:

(i) Entitles Seller to receive a share of the Hydrocarbons produced, saved and marketed from the Target Formation of such Unit (after satisfaction of all royalties, overriding royalties, nonparticipating royalties, net profits interests or other similar burdens on or measured by production of Hydrocarbons) (a "**Net Revenue Interest**"), of not less than the "net revenue interest" share shown in Schedule 2.3 for such Unit, except for (A) decreases in connection with those operations permitted under Section 7.5 in which Seller may after the Execution Date be a non-consenting party, (B) decreases resulting from the elections to ratify or the establishment or amendment of pools or units, to the extent permitted under Section 7.5, received on or after the Execution Date, (C) to the extent constituting Imbalances set forth on Schedule 5.19, decreases required to allow other working interest owners to make up past underproduction or pipelines to make up past under deliveries, and (D) decreases resulting from reversionary interests, carried interests, horizontal or vertical severances or other matters or changes in interest, in each case, as stated in Schedule 2.3;

(ii) Obligates Seller to bear a percentage of the costs and expenses for the maintenance and development of, and operations relating to the Target Formation of any such Unit not greater than the "working interest" above that shown in Schedule 2.3, without increase, except (x) increases resulting from matters stated in Exhibit A-1 or Schedule 2.3, (y) increases arising after the Execution Date resulting from contribution requirements with respect to defaulting parties under applicable operating, unit, pooling, pre-pooling or similar agreements and (z) increases that are accompanied by at least a proportionate increase in Seller's Net Revenue Interest; and

(iii) Is free and clear of liens and encumbrances on title that affect or encumber a Unit (but limited to the Target Formation for such Unit), in each case excluding, subject to and determined without regard to matters constituting Permitted Encumbrances.

(b) As used in this Agreement, the term " **Title Benefit**" shall mean any right, circumstance or condition that operates to (i) increase the Net Revenue Interest of Seller in any Unit shown on Schedule 2.3, without causing a greater than proportionate increase in Seller's working interest above that shown in Schedule 2.3 or (ii) decrease the working interest of Seller in a Unit below that shown on Schedule 2.3 for such Unit without a proportionate or greater than proportionate decrease in the Net Revenue Interest of Seller in such Unit as shown on Schedule 2.3.

(c) As used in this Agreement, the term " **Title Defect**" shall mean any lien, encumbrance, obligation or defect discovered after the Execution Date by Purchaser that causes Seller's title to the Target Formation of any such Unit shown on Schedule 2.3 to be less than Defensible Title; provided that "Title Defect" shall exclude the following:

(i) defects based solely on a lack of information in Seller's files or references to a document if such document is not in Seller's files;

(ii) defects arising out of a lack of corporate or other entity authorization unless Purchaser provides affirmative evidence that the action was not authorized and results in another Person's superior claim of title to the relevant Asset;

(iii) defects in the chain of title consisting of the failure to recite marital status in a document or omissions of successions of heirship or estate proceedings, unless, in each case, Purchaser provides affirmative evidence that such failure or omission could reasonably be expected to result in another Person's superior claim of title to the relevant Asset;

(iv) defects that have been cured by applicable Laws of limitation or prescription;

(v) defects arising out of a lack of survey, unless a survey is expressly required by applicable Laws;

(vi) defects based on a gap in Seller's chain of title in the applicable county records, unless such gap is affirmatively shown to exist in such records by an abstract of title, title opinion or landman's title chain which documents shall be included in a Title Defect Notice;

(vii) defects based upon the failure to record any state or federal Leases or rights-of-way included in the Assets or any assignments of interests in such Leases or rights-of-way included in the Assets in any applicable county records to the extent such recording is not required by the applicable state or federal lessor;

(viii) defects based on the failure to receive or provide an assignment of interests earned under any agreement between or among Seller or its Affiliates on the one hand and Purchaser or its Affiliates on the other hand (including any such agreements with Third Parties);

(ix) any encumbrance or loss of title resulting from Seller's conduct of business in compliance with this Agreement;

(x) encumbrances created under deeds of trust, mortgages and similar instruments by the lessor under a Lease covering the lessor's surface and mineral interests in the land covered thereby that would customarily be accepted (in the region where the Assets are located) in taking or purchasing such Leases and for which a reasonable lessee (in the region where the Assets are located) would not obtain a subordination of such encumbrance to the oil and gas leasehold estate prior to conducting drilling activities on the Lease;

(xi) encumbrances created under deeds of trust, mortgages and similar instruments by the grantor under a right-of-way that would customarily be accepted in taking or purchasing such rights-of-way; and

(xii) defects disclosed herein on the applicable Schedule or Exhibit.

Section 3.3 **Definition of Permitted Encumbrances**. As used herein, the term "**Permitted Encumbrances**" means any or all of the following:

(a) Royalties, nonparticipating royalty interests, net profits interests and any overriding royalties, reversionary interests and other burdens to the extent that they do not, individually or in the aggregate, reduce Seller's Net Revenue Interest below that shown in Schedule 2.3 or increase Seller's working interest above that shown in Schedule 2.3, without a corresponding increase in the Net Revenue Interest;

(b) All leases, unit agreements, pooling agreements, pre-pooling agreements, operating agreements, production sales contracts, division orders and other contracts, agreements and instruments applicable to the Assets, to the extent that they do not, individually or in the aggregate: (i) reduce Seller's Net Revenue Interest below that shown in Schedule 2.3 or increase Seller's working interest above that shown in Schedule 2.3 without a corresponding increase in the Net Revenue Interest or (ii) materially interfere with the ownership and operation of the Assets as currently owned and operated;

(c) Subject to compliance with Sections 3.5 and 7.7, Third Party consents and Preferential Rights applicable to this or a future transaction involving the Assets, including

Third Party consent requirements and similar restrictions with respect to which waivers or consents are obtained by Seller from the appropriate Persons prior to the Closing Date or the appropriate time period for asserting the right has expired or which need not be satisfied prior to a transfer;

(d) Liens for Taxes or assessments not yet delinquent or, if delinquent, being contested in good faith by appropriate actions;

(e) Materialman's, mechanic's, repairman's, contractor's, operator's and other similar liens or charges arising in the ordinary course of business for amounts not yet delinquent (including any amounts being withheld as provided by Law), or if delinquent, being contested in good faith by appropriate actions;

(f) All rights to consent, required notices to, filings with, or other actions by Governmental Bodies in connection with the sale or conveyance of the Assets pursuant to this Agreement if they are not required prior to the sale or conveyance or are of a type customarily obtained after Closing;

(g) To the extent not triggered prior to Closing, rights of reassignment arising upon final intention to abandon or release all or any part of the Assets;

(h) Easements, rights-of-way, servitudes, permits, surface leases and other rights in respect of surface operations to the extent that they do not, individually or in the aggregate, materially interfere with the ownership and operation of the Assets as currently owned and operated as of the Execution Date;

(i) Calls on Hydrocarbon production under existing Contracts disclosed on Schedule 5.11(b) or Schedule 5.19;

(j) All rights reserved to or vested in any Governmental Body to control or regulate any of the Assets in any manner and all obligations and duties under all applicable Laws, rules and orders of any such Governmental Body or under any franchise, grant, license or permit issued by any such Governmental Body, in each case, to the extent generally applying to oil and gas properties located in the region in which the Assets are located;

(k) Any encumbrance on or affecting the Assets which is expressly waived by Purchaser at or prior to Closing or which is discharged by Seller at or prior to Closing;

(l) Any matters shown on Schedule 5.7 or Schedule 3.3(l);

(m) Any matters shown on Schedule 2.3;

(n) Imbalances associated with the Assets;

(o) In the case of any Well for which Seller or its Affiliate is not the operator and that is located on an undeveloped location or other operation that has not been commenced as of the Closing Date, any permits, easements, rights of way, unit designations or production or drilling units not yet obtained, formed or created;

(p) Lack of rights, access or transportation as to any rights of way for gathering or transportation pipelines or facilities that do not constitute any of the Assets;

(q) Any liens, charges, encumbrances, defects or irregularities which affect a Property from which Hydrocarbons have been and are being produced (or to which production of Hydrocarbons is allocable) for the last ten (10) years and for which no claim related to title has been made in writing by any Person during such ten (10) year period;

(r) Any liens, charges, encumbrances, defects or irregularities which (i) would be accepted by a reasonably prudent purchaser engaged in the business of owning and operating oil and gas properties in the region where the Assets are located or (ii) which do not, individually or in the aggregate, materially detract from the value of or materially interfere with the ownership and operation of the Assets subject thereto or affected thereby (as currently owned and operated), and do not reduce Seller's Net Revenue Interest below that shown in Schedule 2.3, or increase Seller's working interest above that shown in Schedule 2.3, without a corresponding increase in the Net Revenue Interest;

(s) Such Title Defects or other defects as Purchaser has waived in writing;

(t) Liens, charges, encumbrances, defects or irregularities released by Seller at Closing; and

(u) All defects or irregularities, to the extent affecting depths, intervals, formations, or strata outside of the Target Formation.

Section 3.4 **Notice of Title Defects Defect Adjustments**.

(a) To assert a Title Defect, Purchaser must deliver claim notices to Seller (each a "**Title Defect Notice**") on or before the date that is thirty (30) days from the date hereof (the "**Title Claim Date**"), except as otherwise provided under Sections 3.5 or 3.6. Each Title Defect Notice shall be in writing and shall include (i) a description of the alleged Title Defect(s), (ii) the Units affected by the Title Defect (each a "**Title Defect Property**"), (iii) the Allocated Values of each Title Defect Property, (iv) supporting documents reasonably necessary for Seller (as well as any title attorney or examiner hired by Seller) to verify the existence of the alleged Title Defect(s) and (v) the amount by which Purchaser reasonably believes the Allocated Values of each Title Defect Property are reduced by the alleged Title Defect(s) and the computations and information upon which Purchaser's belief is based. Purchaser shall be deemed to have waived for all purposes hereunder all Title Defects that were not included in a Title Defect Notice delivered to Seller on or before the Title Claim Date; provided, however, that, subject to Section 7.9(b), such waiver shall not apply to claims under the Special Warranty in the Conveyance. To give Seller an opportunity to commence reviewing and curing alleged Title Defects, Purchaser agrees to use commercially reasonable efforts to provide Seller, on or before the end of each calendar week prior to the Title Claim

Date, written notices of all Title Defects discovered by Purchaser during the preceding calendar week, which notice may be preliminary in nature and supplemented prior to the Title Claim Date.

(b) Seller shall have the right, but not the obligation, to deliver to Purchaser with respect to each Title Benefit discovered by Seller after the Execution Date, a written notice (a "**Title Benefit Notice**") asserting such Title Benefit on or before the Title Claim Date. Each Title Benefit Notice shall include (i) a description of the Title Benefit(s), (ii) the Units affected by the Title Benefit (each a "**Title Benefit Property**"), (iii) the Allocated Values of the Title Benefit Property, (iv) supporting documents reasonably necessary for Purchaser (as well as any title attorney or examiner hired by Purchaser) to verify the existence of the alleged Title Benefit(s) and (v) the amount by which Seller reasonably believes the Allocated Values of those Units are increased by the Title Benefit, and the computations and information upon which Seller's belief is based. Seller shall be deemed to have waived for all purposes hereunder all Title Benefits that were not included in a Title Benefit Notice delivered to Purchaser on or before the Title Claim Date.

(c) Seller shall have the right, but not the obligation, upon delivering written notice to Purchaser no later than Closing, to attempt, at Seller's sole cost, to cure any Title Defects of which it has been timely advised by Purchaser on or before the expiration of sixty (60) days counted from and after the Closing Date (the "**Cure Period**"), unless the Parties otherwise agree. If Seller has provided notice at or prior to the Closing of Seller's intent to attempt to cure a Title Defect within the Cure Period, the affected Property will be conveyed to Purchaser at Closing.

Subject to the application of the Individual TD Threshold and the Title Defect Deductible, the Closing Payment shall be reduced in an amount equal to Purchaser's good faith estimate set forth in a timely delivered Title Defect Notice of the Title Defect Amount for which Seller has elected to cure and such amount by which the Closing Payment is reduced shall be deposited into the Escrow Account pending the post-Closing cure or resolution of such Title Defect in accordance with the terms hereof, which amount shall be disbursed pursuant to the terms of this Agreement and the Escrow Agreement; provided further that if Seller cures such Title Defect prior to the end of the Cure Period, the Parties shall instruct the Escrow Agent to release the Title Defect Amount held in the Escrow Account for such Title Defect within five (5) Business Days of such cure.

However, if, at the end of the Cure Period, the Title Defect is not cured as agreed by Seller and Purchaser or if Seller and Purchaser cannot agree, and it is determined by the Title Arbitrator that such Title Defect is not cured at the end of the Cure Period, then in either case Seller shall either (i) elect one of the options set forth in Section 3.4(d)(i), (d)(ii) or Section 3.4(d)(iii) for such Title Defect, in which event, subject to the application of the Individual TD Threshold and the Title Defect Deductible, the Purchase Price adjustment required in connection with the selected option under this Article 3 shall be made in the final statement of the Adjusted Purchase Price pursuant to Section 9.4(b), and the Parties shall instruct the Escrow Agent to release the Title Defect Amount held in the Escrow Account for such Title Defect within five (5) Business Days after Seller's election hereunder or (ii) submit any disputes in relation to such Title Defects for arbitration pursuant to Section 3.4(h), in which event the Parties shall instruct the Escrow Agent to release the Title Defect Amount held in the Escrow Account for such Title Defect within five (5) Business Days after the final resolution of any dispute with respect to such Title Defect. Notwithstanding the above, no action of Seller in electing or attempting to cure a Title Defect shall constitute a waiver of Seller's right to dispute the existence, nature or value of, or cost to cure, the Title Defect pursuant to Section 3.4(h).

(d) Subject to Section 3.4(h), in the event that (y) any Title Defect asserted by Purchaser in accordance with Section 3.4(a) is not waived by Purchaser and (z) Seller has not provided notice to Purchaser at or prior to the Closing of Seller's intent to attempt to cure the given Title Defect, or Seller has provided such notice but the Title Defect is not cured before the expiration of the Cure Period, then Seller shall, at its sole election, elect to:

(i) reduce the Purchase Price by the Title Defect Amount determined pursuant to Section 3.4(f) or Section 3.4(h);

(ii) if the Title Defect Amount for the affected Title Defect Property is greater than **70%** of the Allocated Value of such Title Defect Property, (A) at Closing, retain the Property that is associated with such Title Defect, in which event the Purchase Price shall be reduced by an amount equal to the Allocated Value of such Property or (B) promptly after expiration of the Cure Period have Purchaser reconvey the Property that is associated with such Title Defect to Seller, in which event the Purchase Price shall be reduced by an amount equal to the Allocated Value of such Property, adjusted as provided in Section 2.2;

(iii) with Purchaser's consent, at its sole option, indemnify Purchaser against all Damages resulting from such Title Defect pursuant to an indemnity agreement in a form reasonably agreeable to Seller and Purchaser; provided, that under no circumstances shall Seller's liability thereunder exceed the Allocated Value for the Title Defect Property made the subject thereof; or

(iv) if applicable, terminate this Agreement pursuant to Article 10.

(e) In the event that any Title Benefit asserted by Seller in accordance with Section 3.4(b) is not waived by Seller, then:

(i) to the extent Purchaser and Seller agree on the Title Benefit Amount as calculated pursuant to Section 3.4(g)(ii), such amount shall be taken into account pursuant to Section 2.2(a)(v); and

(ii) to the extent there is no agreement under Section 3.4(e)(i) on or before the Closing, the disagreement between Seller and Purchaser regarding the Title

Benefit Property or the Title Benefit Amount, as applicable, shall be submitted to arbitration in accordance with Section 3.4(h).

(f) The "**Title Defect Amount**" resulting from a Title Defect shall be determined as follows:

(i) if Purchaser and Seller agree on the Title Defect Amount, then that amount shall be the Title Defect Amount;

(ii) if the Title Defect is a lien, encumbrance or other charge which is undisputed and liquidated in amount, then the Title Defect Amount shall be the amount necessary to be paid to remove the Title Defect from the Title Defect Property;

(iii) if the Title Defect represents a discrepancy between (A) the Net Revenue Interest for any Title Defect Property and (B) the Net Revenue Interest stated on Schedule 2.3, then the Title Defect Amount shall be the product of the Allocated Value of such Title Defect Property multiplied by a fraction, the numerator of which is the actual amount of the decrease in Net Revenue Interest from that stated on Schedule 2.3, and the denominator of which is the Net Revenue Interest stated on Schedule 2.3; provided, however, that if the Title Defect does not affect the Title Defect Property throughout its entire life, the Title Defect Amount shall be reduced to take into account the applicable time period only;

(iv) if the Title Defect represents an obligation, encumbrance, burden or charge upon or other defect in title to the Title Defect Property of a type not described in Section 3.4(f)(i), Section 3.4(f)(ii) or Section 3.4(f)(iii), then the Title Defect Amount shall be determined by taking into account the Allocated Value of the Title Defect Property, the portion of the Title Defect Property affected by the Title Defect, the legal effect of the Title Defect, the potential economic effect of the Title Defect over the life of the Title Defect Property, the values placed upon the Title Defect by Purchaser and Seller and such other factors as are necessary to make a proper evaluation;

(v) if the Title Defect represents (A) a discrepancy between (1) the Net Revenue Interest for any Title Defect Property and (2) the Net Revenue Interest stated on Schedule 2.3 and (B) an obligation, encumbrance, burden or charge upon or other defect in title to the Title Defect Property, then the Title Defect Amount shall be determined by applying both of Section 3.4(f)(iii) and Section 3.4(f)(iv), to such Title Defect, without duplication; and

(vi) notwithstanding anything to the contrary in this Article 3, the aggregate Title Defect Amounts attributable to the effects of all Title Defects upon any Title Defect Property shall not exceed the Allocated Value of such Title Defect Property.

(g) The "**Title Benefit Amount**" resulting from a Title Benefit shall be determined as follows:

(i) if Purchaser and Seller agree on that Title Benefit Amount, then that shall be the Title Benefit Amount;

(ii) if the Title Benefit represents a discrepancy between (A) Seller's Net Revenue Interest for any Title Benefit Property and (B) Seller's Net Revenue Interest set forth in Schedule 2.3 (without any increase in Seller's working interest therein) then the Title Benefit Amount shall be the product of the Allocated Value of the Title Benefit Property multiplied by a fraction, the numerator of which is the actual amount of the increase in Net Revenue Interest from that stated on Schedule 2.3, and the denominator of which is the Net Revenue Interest stated on Schedule 2.3, provided, however, that if the Title Benefit does not affect the applicable Title Benefit Property throughout its entire life, the Title Benefit Amount shall be reduced to take into account the applicable time period only;

(iii) if the Title Benefit is of a type not described above, then the Title Benefit Amount shall be determined by taking into account the Allocated Value of the Asset affected by such Title Benefit, the portion of such Asset affected by such Title Benefit, the legal effect of the Title Benefit, the potential economic effect of the Title Benefit over the life of such Asset, the values placed upon the Title Benefit by Purchaser and Seller and such other reasonable factors as are necessary to make a proper evaluation. For the avoidance of doubt, Title Benefits Amounts shall in no event increase the Purchase Price and will only be used to offset Title Defect Amounts pursuant to Section 2.2(a)(v).

(h) With respect to Title Defect Notices and Title Benefit Notices provided and received on or before the Title Claim Date, Seller and Purchaser shall attempt to agree on all Title Defects, Title Benefits, Title Defect Amounts and Title Benefit Amounts on or before the Closing, subject to Seller's rights under Sections 3.4(d)(ii) and 3.4(d)(iii). If Seller and Purchaser are unable to agree by that date, then subject to Section 3.4(c) and Seller's rights under Sections 3.4(d)(ii) and 3.4(d)(iii), good faith estimates by Purchaser (in the case of Title Defects and Title Defect Amounts) and Seller (in the case of Title Benefits and Title Benefit Amounts) for such disputed matters shall be used for purposes of calculating the Closing Payment pursuant to Section 9.4(a), and the Title Defects, Title Benefits, Title Defect Amounts and Title Benefit Amounts in dispute shall be exclusively and finally resolved by arbitration pursuant to this Section 3.4(h). Likewise, if Seller has provided notice at or prior to the Closing of Seller's intent to attempt to cure a Title Defect and by the end of the Cure Period, Seller and Purchaser have been unable to agree upon the existence of such Title Defect or whether such Title Defect has been cured, or Seller has failed to cure any Title Defects which Seller provided notice that Seller would attempt to cure and Seller and Purchaser have been unable to agree on the existence of such Title Defects or the Title Defect Amounts for such Title Defects, then the cure and/or Title Defect Amounts and Title Benefit Amounts in dispute shall be exclusively and finally resolved by arbitration pursuant to this

Section 3.4(h), subject to Seller's right under Section 3.4(d)(ii). For all matters to be resolved by arbitration pursuant to this Section 3.4(h), a Party must provide notice of its intent to submit such matter to arbitration (i) in the case of the disputed matters referenced in the second sentence of this Section 3.4(h), no later than the Closing and (ii) in the case of the disputed matters referenced in the third sentence of this Section 3.4(h), within ten (10) Business Days after the end of the Cure Period, with such notice identifying the applicable Title Defect Notice timely delivered by Purchaser or Title Benefit Notice Delivered by Seller, as applicable, with respect to such Title Defect or Title Benefit, as applicable, and the matters identified therein that remain unresolved (a "**Title Arbitration Notice**"). Purchaser and Seller shall be deemed to have waived their respective arbitration rights with respect to any Title Defects or Title Benefits, as applicable, which are eligible for arbitration pursuant to this Section 3.4(h) which are not included in a timely Title Arbitration Notice. There shall be a single arbitrator, who shall be a title attorney with at least ten (10) years' experience in oil and gas titles in the State of Texas as selected by mutual agreement of Purchaser and Seller within fifteen (15) days of an election by a Party to submit such dispute to arbitration (or such other time as mutually agreed) and absent such agreement on the selection of the arbitrator, the arbitrator shall be selected by the Houston, Texas office of the American Arbitration Association; provided, however, that in any case such attorney shall not have worked as an employee of or outside counsel for either Seller or Purchaser or any of their Affiliates during the five (5)-year period preceding the applicable arbitration or have any financial interest in the applicable dispute (such attorney, the "**Title Arbitrator**"). The arbitration proceeding shall be held in Houston, Texas and shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association, to the extent such rules do not conflict with the terms of this Agreement. Seller and Purchaser shall each present to the Title Arbitrator, with a simultaneous copy to the other Party, a single written statement of its position on the Title Defects, Title Benefits, Title Defect Amounts and Title Benefit Amounts in dispute, together with a copy of this Agreement and any supporting material that such Party desires to furnish, not later than ten (10) Business Days after appointment of the Title Arbitrator. The Title Arbitrator's determination shall be made within twenty (20) days after submission of the matters in dispute and shall be final and binding upon both Parties, without right of appeal. In determining the existence of each disputed Title Defect and Title Benefit, together with the proper amount of any disputed Title Defect Amount and Title Benefit Amount, Title Arbitrator shall accept Seller's position or Purchaser's position, and Title Arbitrator shall not determine there to be a higher Title Defect Amount or Title Benefit Amount than claimed by the relevant Party, as applicable. In making his determination, the Title Arbitrator shall be bound by the rules set forth in this Section 3.4 and may consider such other matters as in the opinion of the Title Arbitrator are reasonably necessary or helpful to make a proper determination. Additionally, the Title Arbitrator may consult with and engage disinterested Third Parties having expertise in the disputed matter to advise the Title Arbitrator. The Title Arbitrator shall act as an expert for the limited purpose of determining the specific disputed Title Defects, Title Benefits, Title Defect Amounts and Title Benefit Amounts submitted by either Party and may not award damages, interest or penalties to either Party with respect to any matter. Each Party shall bear its own legal fees and other costs of presenting its case and shall bear one-half of the costs and expenses of the Title Arbitrator.

(i) Notwithstanding anything herein to the contrary, (y) in no event shall there be any adjustments to the Purchase Price or other remedies provided to Purchaser for any individual Title Defect for which the Title Defect Amount does not exceed the lesser of (A) **$40,000** and (B) an amount equal to **75%** of the Allocated Value of the relevant Title Defect Property (such lesser amount the "**Individual TD Threshold**"); and (z) in no event shall there be any adjustments to the Purchase Price or other remedies provided to Purchaser for Title Defects unless the aggregate amount of all Title Defect Amounts for Title Defects covered by Section 3.4(d)(i) that exceed the Individual TD Threshold exceeds a deductible in an amount equal to **1.75%** of the Purchase Price (the "**Title Defect Deductible**"), after which point Purchaser shall be entitled to adjustments to the Purchase Price or other available remedies under this Article 3 with respect to all Title Defects in excess of the Title Defect Deductible, subject to the Individual TD Threshold and Seller's elections under Section 3.4(d). The provisions of this Section 3.4(i) shall not apply to Title Defects relating to consent to assignment and Preferential Rights which shall be handled or treated under Section 3.5. The Allocated Value of any Property retained by Seller in accordance with Section 3.4(d)(ii) may not be used in meeting the Title Defect Deductible.

(j) NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS ARTICLE 3 OR OTHERWISE, PURCHASER SHALL NOT BE ENTITLED HEREUNDER TO ASSERT ANY TITLE DEFECTS FOR THOSE ASSETS (OR ANY PORTION THEREOF) FOR WHICH PURCHASER OR ANY OF ITS AFFILIATES SERVES AS OPERATOR, OTHER THAN TITLE DEFECTS ATTRIBUTABLE TO SUCH ASSETS (OR ANY PORTION THEREOF) TO THE EXTENT SUCH TITLE DEFECTS COULD CONSTITUTE A SPECIAL WARRANTY OF TITLE BREACH (AS A RESULT OF A CLAIM BY A THIRD PARTY) BY SELLER UNDER AN ASSIGNMENT OF THE ASSETS BY SELLER.

Section 3.5 **Consents to Assignment and Preferential Rights to Purchase** .

(a) Seller shall use commercially reasonable efforts to promptly (and, in any event, no later than five (5) Business Days following Closing) prepare and send (i) notices to the Third Party holders (excluding Governmental Bodies, which are addressed elsewhere in this Agreement) of any necessary consents to the transactions contemplated hereby (including Required Consents) to request such consents and (ii) notices to the holders of any applicable preferential rights to purchase any Asset that would be applicable in connection with the consummation of the transactions contemplated by this Agreement (each, a "**Preferential Right**") requesting waivers of such Preferential Rights, in each case that would be triggered by the purchase and sale contemplated by this Agreement, and of which Seller has knowledge. The consideration payable under this Agreement for any particular Assets for purposes of Preferential Right notices shall be the Allocated Value for such Assets (proportionately reduced if an Asset is only partially affected). Seller shall use commercially reasonable efforts to cause such consents (including Required Consents) and waivers of Preferential Rights (or the exercise thereof) to be obtained and delivered prior to Closing. As requested, Purchaser shall provide reasonable cooperation to Seller in seeking to obtain such consents (including Required Consents) and waivers of Preferential Rights.

Notwithstanding anything contained herein to the contrary, Seller shall have no liability for failure to obtain such consents or waivers; provided, that such clause will not limit any of Seller's obligations herein with respect to attempting to obtain such consents or waivers.

(b) Seller shall notify Purchaser in writing on or before the Title Claim Date of all consents (including Required Consents) which have not been obtained and the Assets to which they pertain. In no event shall there be included in the Conveyances at Closing any Assets which are then subject to an unobtained Required Consent. In cases where a Required Consent is not obtained prior to the Closing Date, then the Assets associated therewith will not be conveyed to Purchaser at Closing but shall still be considered part of the Assets in accordance with provisions of this Section 3.5, adjustments to the Purchase Price with respect to such Asset will still be made pursuant to Section 2.2, and the Purchase Price will not be reduced as a result of such non conveyance. If any Assets have been excluded from the Assets sold to the Purchaser at Closing due to a failure to obtain a Required Consent in accordance with this Section 3.5, and if a Required Consent has been received or deemed received pursuant to the terms of the underlying agreement on or before the end of the date two (2) year after the Closing Date, the Seller shall so notify the Purchaser within ten (10) Business Days after the Purchaser's receipt of such notice, Seller shall assign and convey to the Purchaser using the form attached as Exhibit B and Purchaser shall accept from Seller such Assets pursuant to the terms of this Agreement. As between the Purchaser and Seller, with respect to any Asset for which a Required Consent has not been obtained by the Closing, (i) the Seller shall hold such Asset as nominee for the Purchaser, effective as of the Effective Time, (ii) the Purchaser shall pay any costs and expenses associated with such Asset, and (iii) Seller shall pay the Purchaser any revenues associated with such Asset for periods from and after the Effective Time. If any Required Consent has not been received or deemed received on or before the two (2) year anniversary of the Closing Date, the Seller shall no longer hold such Asset (collectively, a "**Nonconsented Interest**") as nominee for the Purchaser, and each Party shall repay to the other Party any amounts previously paid hereunder in respect of the Nonconsented Interest (including the Allocated Value and all other amounts of any adjustments pursuant to Section 2.2, with respect to such Nonconsented Interest), and such Nonconsented Interest will be deemed not to have been conveyed to the Purchaser hereunder and shall thereafter be an Excluded Asset. Units excluded pursuant to this Section 3.5(b) will not be deemed to be affected by Title Defects or be subject to Sections 3.2 and 3.4 and the Allocated Value of such excluded properties shall not be applied toward the Title Defect Deductible. In cases where an Asset is subject to a Third Party consent requirement that is not a Required Consent, such Asset shall be included in the Assets at Closing (unless excluded pursuant to the other provisions of this Agreement) and Purchaser shall be responsible after Closing for satisfying such consent requirement at its sole cost, risk and expense, to the extent the applicable consent was not obtained or waived on or prior to Closing.

(c) If any Preferential Right is exercised prior to Closing, the Property transferred to a Third Party as a result of the exercise of such Preferential Right shall be treated as if it was subject to a Title Defect resulting in the complete loss of title and the Purchase Price shall be reduced under Section 2.2(a)(ii) by the Allocated Value for such Property (proportionately reduced if the Preferential Right affects only a portion of such Property). Seller shall retain the consideration paid by the Third Party pursuant to the exercise of such Preferential Right; provided, however, the adjustment made under this Section 3.5(c) for such Property will not be used in determining the Title Defect Deductible. If any Preferential Right is (i) exercised but the transfer with respect to the applicable Asset is not consummated prior to Closing, or (ii) is not exercised and does not expire prior to Closing, then the terms of Section 7.7 shall apply to such right.

Section 3.6 **Casualty or Condemnation Loss**. Subject to the provisions of Sections 8.1(e) and 8.2(e), if, after the date of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty or is taken in condemnation or under right of eminent domain (each, a "**Casualty Loss**"), and the aggregate amount of such Casualty Losses exceeds **$250,000**, Seller shall elect by written notice to Purchaser prior to Closing either (i) to cause the Assets affected by any casualty to be repaired or restored prior to Closing to at least its condition prior to such casualty, at Seller's sole cost (without an adjustment to the Purchase Price pursuant to Section 2.2 or otherwise), as promptly as reasonably practicable (which work may extend after the Closing Date), or (ii) unless such casualty or taking is waived by Purchaser, to exclude the affected Property or Properties from the Assets and reduce the Purchase Price by the Allocated Value thereof or (iii) to include the affected Property or Properties in the Assets to be conveyed at Closing (unless excluded pursuant to the other provisions of this Agreement) and such Casualty Loss shall be treated as a downward Purchase Price adjustment equal to the amount of such Casualty Loss; provided, however, that any adjustment to the Purchase Price pursuant to this Section 3.6 may not be used in meeting the Title Defect Deductible. If all such Casualty Losses do not exceed, in the aggregate, **$250,000**, Seller shall assign, transfer and set over to Purchaser or subrogate Purchaser to all of Seller's or its Affiliates' rights to insurance and other claims against Third Parties with respect to the Casualty Losses.

Section 3.7 **Limitations on Applicability**. The rights of Purchaser under Section 3.1(a) and Section 3.4(a) shall terminate as of the Title Claim Date and be of no further force and effect thereafter; provided there shall be no termination of Purchaser's or Seller's rights under Section 3.4 with respect to any bona fide Title Defect properly reported in a Title Defect Notice or bona fide Title Benefit properly reported in a Title Benefit Notice on or before the Title Claim Date. EXCEPT AS PROVIDED IN THIS ARTICLE 3 AND FOR THE SPECIAL WARRANTY IN THE CONVEYANCE (SUBJECT TO ARTICLE 10 (WITH RESPECT TO PURCHASER'S RIGHT TO TERMINATE THIS AGREEMENT AS A RESULT OF A FAILURE OF THE CLOSING CONDITION IN SECTION 8.2(E) AND ARTICLE 11), PURCHASER RELEASES, REMISES AND FOREVER DISCHARGES THE SELLER INDEMNITEES FROM ANY AND ALL SUITS, LEGAL OR ADMINISTRATIVE PROCEEDINGS, CLAIMS, DEMANDS, DAMAGES, LOSSES, COSTS, LIABILITIES, INTEREST OR CAUSES OF ACTION WHATSOEVER, IN LAW OR IN EQUITY, KNOWN OR UNKNOWN, WHICH PURCHASER MIGHT NOW OR SUBSEQUENTLY MAY HAVE, BASED ON, RELATING TO OR ARISING OUT OF, ANY TITLE DEFECT OR OTHER DEFICIENCY IN OR ENCUMBRANCE ON TITLE TO ANY ASSET.

ARTICLE 4

ENVIRONMENTAL MATTERS

Section 4.1 **Assessment**.

(a) From and after the date hereof and up to and including the Closing Date (or upon the earlier termination of this Agreement) but subject to the limitations set forth herein and in Section 7.1, Purchaser may, at its option, conduct, or cause to be conducted by a reputable environmental consulting or engineering firm approved in advance in writing by Seller (the "**Environmental Consultant**") an environmental assessment of all or any portion of the Seller Operated Assets and/or record reviews, and interviews to the extent relating to the Properties, including their condition and their compliance with Environmental Laws (the "**Phase I Assessment**," together with (y) the investigation conducted pursuant to Section 7.1 and (z) any Phase II Assessment conducted pursuant to Section 4.1(b), the "**Assessment**"). The Assessment shall be conducted at the sole risk, cost and expense of Purchaser, and all of Purchaser's and the Environmental Consultant's activity conducted under this Section 4.1 and Section 7.1 shall be subject to the indemnity provisions of Section 7.6. Subject to Section 4.1(b), Purchaser's right of access shall not entitle Purchaser or the Environmental Consultant to operate equipment or conduct testing or sampling of soil, groundwater or other materials (including any testing or sampling for hazardous substances, Hydrocarbons or NORM). Seller has the right to be present during any activities conducted on the Assets as part of the Assessment. Purchaser shall give Seller reasonable prior written notice before gaining physical access to the Assets. Purchaser shall coordinate the Assessment with Seller to reasonably minimize any inconvenience to or interruption of the conduct of business by Seller. Purchaser shall abide by Seller's, and any Third Party operator's, safety rules, regulations and operating policies (which are communicated/provided to Purchaser) while conducting its due diligence evaluation of the Assets including the Assessment. Purchaser shall promptly provide, but not later than the Environmental Claim Date, copies of all final versions of reports prepared or compiled by Purchaser and/or any of its representatives or agents in connection with the Assessment. Seller shall not be deemed by its receipt of said documents or otherwise to have made any representation or warranty, expressed, implied or statutory, as to the condition of the Assets or the accuracy of said documents or the information contained therein. Upon completion of the Assessment, Purchaser shall at its sole cost and expense and without any cost or expense to Seller or any of its Affiliates (i) repair all damages to the extent caused to any Assets by or in connection with the Assessment (including due diligence conducted by Purchaser's environmental consulting or engineering firm but excluding any damage to the extent attributable to conditions or defects existing prior to the Assessment), (ii) to the extent resulting from or in connection with the Assessment, restore the Assets to the approximate same condition as, or better condition than, they were prior to commencement of the Assessment, and (iii) remove all equipment, tools and other property brought onto the Assets in connection with the Assessment. During all periods that Purchaser or any of its representatives or contractors are on the Assets, Purchaser shall maintain, at its sole expense and with reputable insurers, such insurance as is reasonably sufficient to support Purchaser's indemnity obligations under Section 7.6. All information (including all reports, results and documentation containing such information) acquired by Purchaser, its agents or representatives, or the Environmental Consultant, in conducting the Assessment under this Section shall be subject to the confidentiality restrictions set forth in the Confidentiality Agreement. In the event this Agreement is terminated prior to Closing, Purchaser shall return to Seller (or certify the destruction of) all copies of all such information and data, as well as any derivative reports, analysis or other items derived or based on any of such information or data.

(b) If, in the professional judgment of the Environmental Consultant performing the Phase I Assessment as set forth in the final report delivered by such Environmental Consultant in connection therewith, it is determined that Phase II sampling or other invasive investigations are necessary in order for Purchaser to prove the existence of an Environmental Defect (a "**Phase II Assessment**"), Purchaser will have the right but not the obligation to furnish Seller, on or prior to the Environmental Claim Date with a written description prepared by such Environmental Consultant of the proposed scope of such sampling or invasive activities, including a description of (y) the specific activities to be conducted and (z) the approximate location and expected timing of such activities (a "**Phase II Request**"), as well as the final report recommending such Phase II Assessment. Purchaser shall not undertake any activities set forth in a Phase II Request without first obtaining the prior written consent of Seller (such consent to be granted or withheld in Seller's sole discretion). Any Phase II Assessment will be conducted by a reputable environmental consulting or engineering firm approved in advance by Seller (such approval of such Environmental Consultant or firm not to be unreasonably withheld, conditioned, or delayed). If, within five (5) Business Days of Purchaser's delivery of the Phase II Request, Seller does not approve said Phase II Request, then Purchaser will have the right to exclude the affected Assets from the Closing and the Purchase Price will be adjusted downward by the Allocated Value of such Assets in accordance with Section 2.2(a)(xvii). If Seller approves the Phase II Request, the Environmental Claim Date will be extended to the fifth (5^{th}) Business Day prior to Closing, solely with respect to the matters set forth in the applicable timely delivered Phase II Request for which such Phase II Assessment is to be conducted and then solely to the extent such matters are substantiated in such Phase II Assessment.

Section 4.2 **NORM**. Purchaser acknowledges the following:

(a) The Assets have been used for exploration, development, and production of oil and gas and that there may be petroleum, produced water, wastes, or other materials located on or under the Properties or associated with the Assets.

(b) Equipment and sites included in the Assets may contain asbestos, hazardous substances, or NORM.

(c) NORM may affix or attach itself to the inside of wells, materials, and equipment as scale, or in other forms.

(d) The wells, materials, and equipment located on the Properties or included in the Assets may contain NORM and other wastes or hazardous substances.

(e) NORM containing material and other wastes or hazardous substances may have come in contact with the soil.

(f) Special procedures may be required for the remediation, removal, transportation, or disposal of soil, wastes, asbestos, hazardous substances, and NORM from the Assets.

Section 4.3 **Notice of Violations of Environmental Laws** . Purchaser shall deliver any claim notices to Seller in writing (an "**Environmental Defect Notice**"), on or before the date that is thirty (30) days from the date hereof (the "**Environmental Claim Date**"), of each individual environmental matter affecting an Asset that is disclosed by the Assessment that Purchaser reasonably believes in good faith may constitute or result in Environmental Liabilities for which the Lowest Cost Response to address the matter exceeds **$70,000** (the "**Individual ED Threshold**") (each such environmental matter affecting an Asset, an "**Environmental Defect**"), including in the Environmental Defect Notice (i) a reasonably detailed description of the specific matter that constitutes an Environmental Defect, including (A) the written conclusion of Purchaser or Purchaser's Environmental Consultant that Environmental Liabilities exist, which conclusion shall be reasonably substantiated by the factual data gathered in Purchaser's Assessment and (B) a separate specific citation of the provisions of Environmental Laws alleged to be violated and the related facts that substantiate such violation; (ii) the Assets affected; (iii) a detailed estimate of the Lowest Cost Response to cure or eliminate the alleged matter in question; and (iv) supporting documents reasonably necessary for Seller (as well as any consultant, inspector or expert hired by Seller) to verify the existence of the facts alleged in the Environmental Defect Notice. Purchaser shall use commercially reasonable efforts to furnish Seller, on or before the end of each calendar week prior to the Environmental Claim Date, Environmental Defect Notices with respect to any Environmental Defect that any of Purchaser's or any of its Affiliate's employees, representatives, attorney or other environmental personnel or contractors, including the Environmental Consultant, discover or become aware of during the preceding calendar week, which notice may be preliminary in nature and supplemented prior to the Environmental Claim Date.

Section 4.4 **Remedies for Violations of Environmental Laws** .

(a) If Seller believes any individual matter described in an Environmental Defect Notice delivered pursuant to Section 4.3 may constitute or result in Environmental Liabilities for which the Lowest Cost Response to address the matter exceeds the Individual ED Threshold, then Seller shall, at its sole election prior to the Closing, elect to:

(i) reduce the Purchase Price by the lesser of (A) the amount set forth in the applicable Environmental Defect Notice, (B) the Allocated Value of the affected Unit or (C) such amount otherwise agreed upon in writing by Purchaser and Seller, in each case, as being a reasonable estimate of the cost of curing the matter described in such Environmental Defect Notice;

(ii) if the Lowest Cost Response therefor is greater than **70%** of the aggregate Allocated Values of the affected Assets, retain the Assets that are associated with such Environmental Defect Notice and affected by such matter, in which event the Purchase Price shall be reduced by an amount equal to the Allocated Values of such Assets;

(iii) perform or cause to be performed prior to Closing, at the sole cost and expense of Seller, such operations as may be necessary to bring such affected Assets into compliance with the applicable Environmental Law disclosed in such Environmental Defect Notice;

(iv) enter into an agreement with Purchaser whereby Seller will as soon as reasonably practicable after Closing, at the sole cost and expense of Seller, perform or cause to be performed such operations as may be necessary to bring such affected Asset into compliance with the applicable Environmental Law disclosed in such Environmental Defect Notice;

(v) with Purchaser's consent, at its sole option, indemnify Purchaser against all Damages resulting from such Environmental Liability pursuant to an indemnity agreement in a form reasonably agreeable to Seller and Purchaser; provided, that, under no circumstances shall Seller's aggregate liability thereunder exceed the lesser of either the Allocated Value for the Asset made the subject thereof or the Lowest Cost Response for such Environmental Liability; or

(vi) if applicable, terminate this Agreement pursuant to Article 10;

provided that, notwithstanding the foregoing, if the Lowest Cost Response (as asserted by Purchaser in good faith as part of an Environmental Defect Notice) for any affected Asset exceeds the greater of **70%** of the Allocated Value of such affected Asset and the Individual ED Threshold, Purchaser will, at its sole option, have the right to require that Seller retain the affected Asset at Closing pursuant to Section 4.4(a)(ii).

(b) In the event that (i) Seller elects to proceed under Section 4.4(a)(i) and Purchaser and Seller have failed to agree by Closing on the reduction to the Purchase Price (which agreement Seller and Purchaser shall use good faith efforts to reach) or (ii) Purchaser and Seller cannot otherwise agree on the existence, extent or amount of Environmental Liabilities alleged in an Environmental Defect Notice before Closing, Seller shall then proceed with respect to such matter under any of Sections 4.4(a)(ii), (a)(iii), (a)(iv), (a)(v) or (a)(vi) or submit such dispute to arbitration pursuant to this Section 4.4. In the event that Seller elects to proceed under Section 4.4(a)(iv) or (a)(v), and Purchaser and Seller have failed to agree by Closing on the terms of the agreement contemplated thereby (which agreement Seller and Purchaser shall use good faith efforts to reach), Seller shall then proceed with respect to such matter under any of the other parts of Section 4.4(a) or submit such dispute to arbitration pursuant to this Section 4.4.

(c) For all matters to be resolved by arbitration pursuant to this Section 4.4, a Party must provide notice of its intent to submit such matter to arbitration on or before the Closing, with such notice identifying the applicable Environmental Defect Notice timely delivered by Purchaser with respect to such Environmental Defect and the matters identified therein that remain unresolved (a "**Environmental Arbitration Notice**"). There shall be a single arbitrator, who shall be an environmental consultant with at least ten (10) years' relevant experience in the oil and gas industry as selected by mutual agreement of Purchaser and Seller within fifteen (15) days of an election by a Party to submit such dispute to arbitration. Absent such agreement on the selection of the arbitrator, the arbitrator shall be selected by the Houston, Texas office of the American Arbitration Association (the "**Environmental Arbitrator**"). Each Party shall be deemed to have waived its arbitration rights with respect to any Environmental Defects which are eligible for arbitration pursuant to this Section 4.4 which are not included in a timely Environmental Arbitration Notice. The arbitration proceeding shall be held in Houston, Texas and shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association, to the extent such rules do not conflict with the terms of this Agreement. Seller and Purchaser shall each present to the Environmental Arbitrator, with a simultaneous copy to the other Party, a single written statement of its position on the matter in dispute pursuant to this Section 4.4, together with a copy of this Agreement and any supporting material that such Party desires to furnish, not later than ten (10) Business Days after appointment of the Environmental Arbitrator. The Environmental Arbitrator's determination shall be made within twenty (20) days after submission of the matters in dispute and shall be final and binding upon both parties, without right of appeal. In determining the existence of each disputed Environmental Defect and the proper amount of any adjustment to the Purchase Price for each disputed Environmental Defect Amount, the Environmental Arbitrator shall accept Seller's position or Purchaser's position, and the Environmental Arbitrator shall not determine there to be a higher Environmental Defect Amount than claimed by Purchaser or a lower Environmental Defect Amount than claimed by Seller. In making his determination, the Environmental Arbitrator shall be bound by the rules set forth in this Article 4 and may consider such other matters as in the opinion of the Environmental Arbitrator are reasonably necessary or helpful to make a proper determination. In connection with the determination of a matter submitted to the Environmental Arbitrator, Purchaser may not assert any violation of Environmental Law that is not specified by Purchaser in the applicable Environmental Defect Notice. The Environmental Arbitrator shall act as an expert for the limited purpose of determining the specific disputed Environmental Liability or the Lowest Cost Response for such Environmental Liability submitted by Seller and may not award damages, interest or penalties to either Party with respect to any matter nor may it award Purchaser a greater amount with respect to the applicable Environmental Liability than the Lowest Cost Response set forth by Purchaser in the applicable Environmental Claim Notice. Seller and Purchaser shall each bear its own legal fees and other costs of presenting its case. Each Party shall bear one-half of the costs and expenses of the Environmental Arbitrator. If the validity of any Environmental Liability or the Lowest Cost Response attributable thereto, is not determined prior to Closing by the Environmental Arbitrator pursuant to this Section 4.4, subject to Seller's and Purchaser's right to exclude the affected Asset pursuant to the proviso in Section 4.4(a), (i) all affected Properties shall be conveyed to Purchaser at Closing,

(ii) subject to the application of the Individual ED Threshold and the Environmental Defect Deductible, the Closing Payment shall be reduced in an amount equal to the Purchaser's good faith estimate of the Lowest Cost Response for the applicable Environmental Liability, and (iii) such amount by which the Closing Payment is reduced shall be deposited into the Escrow Account, which amount shall be disbursed pursuant to the terms of this Agreement and the Escrow Agreement; provided further that once the Environmental Arbitrator finally determines the validity of any Environmental Liability or the Lowest Cost Response with respect thereto, the Parties shall instruct the Escrow Agent to release the amount held in the Escrow Account for such dispute within five (5) Business Days of such resolution.

(d) Notwithstanding anything herein to the contrary, (i) in no event shall there be any adjustments to the Purchase Price or other remedies provided to Purchaser for individual Environmental Liabilities for which the Lowest Cost Response to address same does not exceed the Individual ED Threshold; and (ii) in no event shall there be any adjustments to the Purchase Price or other remedies provided to Purchaser for Environmental Liabilities unless and until the sum of the aggregate amount of all Environmental Liabilities covered by Section 4.4(a) that exceed the Individual ED Threshold, exceeds a deductible in an amount equal to **1.75%** of the Purchase Price (the "**Environmental Defect Deductible**"), after which point Purchaser shall be entitled to adjustments to the Purchase Price or other available remedies under this Section 4.4 with respect to Environmental Liabilities in excess of such Environmental Defect Deductible, subject to the Individual ED Threshold and Seller's elections under this Section 4.4. The Allocated Value of any Property (or affected portion thereof) retained by Seller in accordance with Section 4.4(a)(ii) may not be used in meeting the Environmental Defect Deductible.

(e) NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS ARTICLE 4 OR OTHERWISE, PURCHASER SHALL NOT BE ENTITLED HEREUNDER TO ASSERT ANY ENVIRONMENTAL DEFECTS FOR THOSE OF THE ASSETS FOR WHICH PURCHASER OR ANY OF ITS AFFILIATES SERVES AS OPERATOR.

Section 4.5 **Limitations**. Notwithstanding anything to the contrary in this Agreement, except for the indemnity provided under Section 11.2(c) as it relates to Retained Obligations (limited to Clause (d) of the definition thereof) and/or breaches of the representation in Section 5.15, this Article 4 (without prejudice to Purchaser's right to terminate this Agreement pursuant to Article 10 as a result of the failure of the closing condition in Section 8.2(e)) is intended to be the sole and exclusive remedy that Purchaser Indemnitees shall have against Seller Indemnitees with respect to any matter or circumstance relating to Environmental Defects, Environmental Laws, Environmental Liabilities, the release or threatened release of materials into the environment or protection of the environment, natural resources, threatened or endangered species or health. Except to the limited extent necessary to enforce the terms of this Article 4 (without prejudice to Purchaser's right to terminate this Agreement pursuant to Article 10 as a result of the failure of the closing condition in Section 8.2(e)) and the indemnity provided under Section 11.2(c) as it relates to Retained Obligations (limited to clause (d) of the definition thereof) and/or breaches of the representation in Section 5.15, Purchaser (on behalf of itself, each of the other Purchaser Indemnitees and their respective insurers and successors in interest) hereby releases and discharges any and all claims and remedies at Law or in equity, known or unknown, whether now existing or arising in the future, contingent or otherwise, against the Seller Indemnitees with respect to any matter or circumstance relating to Environmental Defects, Environmental Laws, Environmental Liabilities, the release or threatened release of materials into the environment or protection of the environment, natural resources, threatened or endangered species, or health EVEN IF SUCH CLAIMS OR DAMAGES ARE CAUSED IN WHOLE OR IN PART BY THE NEGLIGENCE (WHETHER SOLE, JOINT OR CONCURRENT, EXCLUDING GROSS NEGLIGENCE AND WILLFUL MISCONDUCT), STRICT LIABILITY OR OTHER LEGAL FAULT OF SELLER INDEMNITEES. Except as expressly provided in Section 5.15, Purchaser acknowledges that Seller has not made and will not make any representation or warranty regarding any matter or circumstance relating to Environmental Defects, Environmental Laws, Environmental Liabilities, the release or threatened release of materials into the environment or protection of the environment, natural resources, threatened or endangered species, or health, and that except as set forth in Section 5.15, nothing in Article 5 or otherwise shall be construed as such a representation or warranty.

ARTICLE 5

REPRESENTATIONS AND WARRANTIES OF SELLER

Section 5.1 **Disclaimers**.

(a) EXCEPT AS AND TO THE EXTENT EXPRESSLY SET FORTH IN ARTICLE 5 OF THIS AGREEMENT OR IN THE CERTIFICATE OF SELLER TO BE DELIVERED PURSUANT TO SECTION 9.2(G), OR FOR THE SPECIAL WARRANTY IN THE CONVEYANCE (AND WITHOUT LIMITING PURCHASER'S REMEDIES UNDER ARTICLE 10 (WITH RESPECT TO PURCHASER'S RIGHT TO TERMINATE THIS AGREEMENT AS A RESULT OF A FAILURE OF THE CLOSING CONDITION IN SECTION 8.2(A)) OR ARTICLE 11), WITH RESPECT TO THE ASSETS AND THE TRANSACTIONS CONTEMPLATED HEREBY (i) SELLER MAKES NO REPRESENTATIONS OR WARRANTIES, STATUTORY, EXPRESS OR IMPLIED, AND (ii) PURCHASER HAS NOT RELIED UPON, AND SELLER EXPRESSLY DISCLAIMS ALL LIABILITY AND RESPONSIBILITY FOR, ANY REPRESENTATION, WARRANTY, STATEMENT OR INFORMATION MADE OR COMMUNICATED (ORALLY OR IN WRITING) TO PURCHASER OR ANY OF ITS AFFILIATES, OR ITS OR THEIR EMPLOYEES, AGENTS, OFFICERS, DIRECTORS, MEMBERS, MANAGERS, EQUITY OWNERS, CONSULTANTS, REPRESENTATIVES OR ADVISORS (INCLUDING ANY OPINION, INFORMATION, PROJECTION OR ADVICE THAT MAY HAVE BEEN PROVIDED TO PURCHASER BY ANY EMPLOYEE, AGENT, OFFICER, DIRECTOR, MEMBER, MANAGER, EQUITY OWNER, CONSULTANT, REPRESENTATIVE OR ADVISOR OF SELLER OR ANY OF ITS AFFILIATES).

(b) EXCEPT AS AND TO THE EXTENT EXPRESSLY SET FORTH IN ARTICLE 5 OR IN THE CERTIFICATE OF SELLER TO BE DELIVERED PURSUANT

TO SECTION 9.2(G), OR FOR THE SPECIAL WARRANTY IN THE CONVEYANCE (AND WITHOUT LIMITING PURCHASER'S REMEDIES UNDER ARTICLE 10 (WITH RESPECT TO PURCHASER'S RIGHT TO TERMINATE THIS AGREEMENT AS A RESULT OF A FAILURE OF THE CLOSING CONDITION IN SECTION 8.2(A) OR SECTION 8.2(E)) OR ARTICLE 11), WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, SELLER (Y) EXPRESSLY DISCLAIMS, AND PURCHASER ACKNOWLEDGES AND AGREES THAT IT HAS NOT RELIED UPON, ANY REPRESENTATION OR WARRANTY, STATUTORY, EXPRESS OR IMPLIED, AS TO (i) TITLE TO ANY OF THE ASSETS, (ii) THE CONTENTS, CHARACTER OR NATURE OF ANY DESCRIPTIVE MEMORANDUM, OR ANY REPORT OF ANY PETROLEUM ENGINEERING CONSULTANT, OR ANY GEOLOGICAL OR SEISMIC DATA OR INTERPRETATION, RELATING TO THE ASSETS, (iii) THE QUANTITY, QUALITY OR RECOVERABILITY OF PETROLEUM SUBSTANCES IN OR FROM THE ASSETS, (iv) ANY ESTIMATES OF THE VALUE OF THE ASSETS OR FUTURE REVENUES GENERATED BY THE ASSETS, (v) THE PRODUCTION OF PETROLEUM SUBSTANCES FROM THE ASSETS, (vi) ANY ESTIMATES OF OPERATING COSTS AND CAPITAL REQUIREMENTS FOR ANY WELL, OPERATION, OR PROJECT, (vii) THE MAINTENANCE, REPAIR, CONDITION, QUALITY, SUITABILITY, DESIGN OR MARKETABILITY OF THE ASSETS, (viii) THE CONTENT, CHARACTER OR NATURE OF ANY DESCRIPTIVE MEMORANDUM, REPORTS, BROCHURES, CHARTS OR STATEMENTS PREPARED BY THIRD PARTIES, (ix) ANY OTHER MATERIALS OR INFORMATION THAT MAY HAVE BEEN MADE AVAILABLE OR COMMUNICATED TO PURCHASER OR ITS AFFILIATES, OR ITS OR THEIR EMPLOYEES, AGENTS, OFFICERS, DIRECTORS, MEMBERS, MANAGERS, EQUITY OWNERS, CONSULTANTS, REPRESENTATIVES OR ADVISORS IN CONNECTION WITH THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT OR ANY DISCUSSION OR PRESENTATION RELATING THERETO, AND (Z) FURTHER DISCLAIMS (AND PURCHASER ACKNOWLEDGES AND AGREES THAT IT HAS NOT RELIED UPON) ANY REPRESENTATION OR WARRANTY, STATUTORY, EXPRESS OR IMPLIED, OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE OR CONFORMITY TO MODELS OR SAMPLES OF MATERIALS OF ANY EQUIPMENT, IT BEING EXPRESSLY UNDERSTOOD AND AGREED BY THE PARTIES THAT, WITHOUT LIMITING ITS RIGHTS AND REMEDIES SET FORTH HEREIN, (I) PURCHASER HAS OR, BY CLOSING, WILL HAVE INSPECTED, OR WAIVED PURCHASER'S RIGHT TO INSPECT, THE ASSETS FOR ALL PURPOSES AND SATISFIED ITSELF AS TO THEIR PHYSICAL AND ENVIRONMENTAL CONDITION, BOTH SURFACE AND SUBSURFACE, INCLUDING BUT NOT LIMITED TO CONDITIONS SPECIFICALLY RELATED TO THE PRESENCE, RELEASE OR DISPOSAL OF HAZARDOUS SUBSTANCES, SOLID WASTES OR NORM, (II) PURCHASER SHALL BE DEEMED TO BE OBTAINING THE ASSETS, INCLUDING THE EQUIPMENT, IN ITS PRESENT STATUS, CONDITION AND STATE OF REPAIR, "AS IS" AND "WHERE IS" WITH ALL FAULTS AND DEFECTS, AND (III) PURCHASER HAS OR, BY CLOSING, WILL HAVE MADE OR CAUSED TO BE MADE SUCH INSPECTIONS AS PURCHASER DEEMS APPROPRIATE.

(c) PURCHASER ACKNOWLEDGES AND AGREES THAT, EXCEPT FOR POSITIONS TAKEN ON A TAX RETURN WITH RESPECT TO ASSET TAXES FOR A TAXABLE PERIOD BEGINNING BEFORE AND ENDING AFTER THE EFFECTIVE TIME WHERE SUCH POSITION IS BASED ON COMMENTS RECEIVED FROM SELLER AND IMPLEMENTED BY PURCHASER PURSUANT TO SECTION 7.8(B) (IN WHICH CASE PURCHASER CAN RELY ON SUCH POSITION SOLELY FOR SUCH TAXABLE PERIOD) PURCHASER CANNOT RELY ON OR FORM ANY CONCLUSIONS FROM SELLER'S METHODOLOGIES FOR THE DETERMINATION AND REPORTING OF ANY ASSET TAXES THAT WERE UTILIZED FOR ANY TAX PERIOD (OR PORTION THEREOF) BEGINNING PRIOR TO THE CLOSING DATE FOR PURPOSES OF CALCULATING AND REPORTING ASSET TAXES ATTRIBUTABLE TO ANY TAX PERIOD (OR PORTION THEREOF) BEGINNING AFTER THE CLOSING DATE, IT BEING UNDERSTOOD THAT PURCHASER MUST MAKE ITS OWN DETERMINATION AS TO THE PROPER METHODOLOGIES THAT CAN OR SHOULD BE USED FOR ANY SUCH LATER TAX RETURN.

(d) Any representation "to the knowledge of Seller", "to Seller's knowledge" or references to any matters that Seller "knew", including such matters set forth in Section 11.4(f), is limited to matters within the "actual knowledge" of the Persons set forth on Exhibit C.

(e) Inclusion of a matter on a Schedule to a representation or warranty which addresses matters having a material or Material Adverse Effect shall not be deemed an indication that such matter does, or may, have a material or Material Adverse Effect. Matters may be disclosed on a Schedule to this Agreement for purposes of information only. Matters disclosed in each Schedule shall qualify the representation and warranty in which such Schedule is referenced and any other representation and warranty to which the applicability of matters disclosed is reasonably apparent on its face.

(f) From time to time prior to the Closing Date, Seller shall have the right (but not the obligation) to supplement or amend the Schedules hereto to correct any matter that would otherwise constitute a breach of any representation or warranty of Seller contained herein (each a "**Schedule Supplement**"), and each such Schedule Supplement shall be deemed to be incorporated into and supplement and amend the Schedules with respect to matters arising between the Execution Date and the Closing Date for all purposes hereunder; provided, however, that any such Schedule Supplement shall be disregarded for purposes of, and shall not affect, (i) Purchaser's conditions to Closing set forth in Section 8.2 or (ii) Purchaser's remedies under Section 11.2(c)(ii) with respect to any breaches of Seller's representations related to the Seller Operated Assets that do not individually or in the aggregate give rise to a right by Purchaser to terminate this Agreement pursuant to Section 10.1(c).

(g) WITHOUT LIMITING ANY KNOWLEDGE QUALIFIERS OTHERWISE SET FORTH HEREIN, ALL SUCH REPRESENTATIONS AND WARRANTIES ARE

DEEMED TO BE QUALIFIED TO SELLER'S KNOWLEDGE IN THE CASE OF ASSETS THAT DO NOT CONSTITUTE SELLER OPERATED ASSETS.

(h) Subject to the foregoing provisions of this Section 5.1, and the other terms and conditions of this Agreement, Seller represents and warrants to Purchaser the matters set out in Section 5.2 through Section 5.21 as of the date of this Agreement, as modified by the Schedules.

Section 5.2 **Existence and Qualification**. Seller is duly organized, validly existing and in good standing under the Laws of the state of Delaware and is duly qualified to do business in Texas. Seller has all requisite power and authority to own and operate its property (including the Assets) and to carry on its business as now conducted.

Section 5.3 **Power**. Seller has the requisite power to enter into and perform this Agreement and consummate the transactions contemplated by this Agreement.

Section 5.4 **Authorization and Enforceability**. The execution, delivery and performance of this Agreement, and the performance of the transactions contemplated hereby, have been duly and validly authorized by all necessary action on the part of Seller. This Agreement has been duly executed and delivered by Seller (and all documents required hereunder to be executed and delivered by Seller at Closing will be duly executed and delivered by Seller) and this Agreement constitutes, and at the Closing such documents will constitute, the valid and binding obligations of Seller, enforceable in accordance with their terms except as such enforceability may be limited by applicable bankruptcy, insolvency or other similar Laws affecting creditors' rights generally as well as to general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at Law).

Section 5.5 **No Conflicts**. The execution, delivery and performance of this Agreement by Seller, and the transactions contemplated by this Agreement, will not (a) violate any provision of the governing documents of Seller, (b) result in a material default (with due notice or lapse of time or both) or the creation of any lien or encumbrance, or give rise to any right of termination, cancellation or acceleration under any of the terms, conditions or provisions of any promissory note, bond, mortgage, indenture, loan or similar financing instrument to which Seller is a party or by which Seller or the Assets may be bound, (c) violate in any material respect any judgment, order, ruling, or decree applicable to Seller as a party in interest or (d) violate in any material respect any Laws applicable to Seller or any of the Assets (except for rights to consent by, required notices to, and filings with or other actions by Governmental Bodies where the same are not required prior to the assignment of oil and gas interests).

Section 5.6 **Liability for Brokers' Fees**. Purchaser shall not directly or indirectly have any responsibility, liability or expense, as a result of undertakings or agreements of Seller, for brokerage fees, finder's fees, agent's commissions or other similar forms of compensation in connection with this Agreement or any agreement or transaction contemplated hereby.

Section 5.7 **Litigation**. Except as disclosed on Schedule 5.7, there are no actions, suits or proceedings pending for which Seller has received written notice, or to Seller's knowledge threatened in writing, before any Governmental Body or arbitrator to which the Assets are subject or that would otherwise prevent or hinder the consummation of the transactions contemplated by this Agreement or Seller's performance of its obligations hereunder; and there has been no settlement of litigation with Third Parties or order of any Governmental Body with respect to the ownership or operation of the Assets that would be binding on Purchaser (or adversely affect the Assets) after Closing.

Section 5.8 **Asset Taxes and Assessments**. Except as set forth on Schedule 5.8, Seller warrants and represents, as to the Seller Operated Assets, that (a) all material Asset Taxes that have become due and payable by Seller have been timely paid in full, (b) all material reports, returns, statements (including estimated reports, returns or statements), and other similar filings with respect to Asset Taxes (the "**Tax Returns**") required to be filed by Seller have been timely filed (taking into account all applicable extensions) with the appropriate Governmental Body in all jurisdictions in which such Tax Returns are required to be filed; (c) such Tax Returns are true and correct in all material respects; (d) there is not currently in effect any extension or waiver of any statute of limitations regarding the assessment or collection of any Asset Tax with respect to the Assets, which period has not yet expired; (e) there are no administrative proceedings or lawsuits pending with respect to any Asset Tax with respect to the Assets by any taxing authority for which Seller has received written notice; and (f) there are no liens on any of the Assets attributable to Taxes other than liens for Taxes not yet due. Except as set forth on Schedule 5.8, none of the Assets is, or prior to the Closing will be, subject to a Tax partnership or related reporting obligations for U.S. federal income tax purposes. With respect to any Tax partnership that is set forth on Schedule 5.8, Seller is responsible for compliance with all tax reporting obligations of the Tax partnership (including filing income tax returns of the Tax partnership). With respect to each Tax partnership that is set forth on Schedule 5.8, the capital account balance in respect of such Tax partnership that Purchaser will be deemed to acquire as a result of the purchase of the Assets pursuant to this Agreement will be the portion of Seller's capital account balance attributable to the purchased Assets as of the Closing, and the amount of such capital account balance of Purchaser attributable to the purchased Assets immediately following the Closing will be at least 65% of the aggregate capital account balances immediately following the Closing of all persons who are treated as partners of such Tax partnership (including Purchaser) which are attributable to their respective interests in the properties underlying the Assets. Neither Seller nor any of its Affiliates is a party to or is bound by any Tax allocation or Tax sharing or indemnification agreement with respect to the Assets. Notwithstanding anything in this Agreement to the contrary, this Section 5.8 contains the exclusive representations and warranties with respect to Tax matters, and no other Section in this Article 5 shall apply to Tax matters.

Section 5.9 **Outstanding Capital Commitments**. As of the date of this Agreement, there is no individual outstanding authority for expenditure which is (or, as of the Effective Time, was) binding on the Assets, the value of which Seller reasonably anticipates exceeds **$100,000** chargeable to Seller's interests participating in the operation covered by such authority for expenditure after the Effective Time, other than those shown on Schedule 5.9 hereto.

Section 5.10 **Compliance with Laws**. Except as disclosed on Schedule 5.10, the Assets are, and the operation of the Assets has been and currently is, in compliance in all material respects with the provisions and requirements of all Laws (excluding Environmental Laws, which are addressed in Section 5.15) of all Governmental Bodies having jurisdiction with respect to the Assets, or the ownership, operation, development, maintenance, or use of any thereof.

Section 5.11 **Contracts**. Seller is not and, to Seller's knowledge, no other party is, in default or breach under any Contract except as disclosed on Schedule 5.11(a). Schedule 5.11(b) sets forth all of the following Contracts included in the Assets or to which any of the Assets or Purchaser will be bound, in each case, from and after the Effective Time (each, a "**Material Contract**"): (a) any Contract that can reasonably be expected to result in aggregate payments or obligations by or revenues of more than **$100,000** during the remainder of the current or any subsequent fiscal year (based solely on the terms thereof and current volumes, without regard to any expected increase in volumes or revenues); (b) any agreement with any Affiliate of Seller; (c) any agreement or contract for the sale, exchange, or other disposition of, or for the transportation, gathering, marketing, treating, processing or similar Contracts of, Hydrocarbons produced from or attributable to the Assets that is not cancelable without penalty or other material payment on not more than sixty (60) days' prior written notice; (d) any agreement of or binding upon Seller to sell, lease, farmout, or otherwise dispose of any interest in any of the Assets after the Effective Time; (e) any exploration agreement, participation agreement, development agreement, unit operating agreement, joint operating agreement or similar Contract; (f) any Contract that constitutes a lease under which Seller is the lessor or the lessee of real or personal property which involves an annual base rental of more than **$100,000**; (g) area of mutual interest agreements and farmout and farmin agreements or agreements that otherwise contain material non-competition restrictions, or material rights of first refusal, or other similar restrictions; (h) any Contract the sole purpose of which (as of the execution of such Contract) is to indemnify another Person; and (i) any indenture, mortgage, loan, credit lien, sale-leaseback or similar Contract affecting any of the Assets that will not be released on or prior to the Closing. No currently effective notices have been received by Seller or any of its Affiliates of the exercise of any premature termination, price redetermination, market-out, shut-in or curtailment of or under any Material Contract. Seller has made available to Purchaser full, true and correct copies of all Material Contracts (including all material amendments thereto) that are not in the possession of or otherwise available to Purchaser.

Section 5.12 **Payments for Production**. Except as set forth on Schedule 5.12, Seller is (and, from and after the Effective Time, was) not obligated under any contract or agreement containing a take-or-pay, advance payment, prepayment, or similar provision (including volumetric production payments and net profits interests), or under any gathering, transmission, or any other contract or agreement with respect to any of the Seller Operated Assets to sell, gather, deliver, process, or transport any Hydrocarbons without then or thereafter receiving full payment therefor, and Seller is not obligated to pay any penalties under any agreement as a result of the delivery of quantities of Hydrocarbons under or in excess of any such agreement's requirements.

Section 5.13 **Governmental Authorizations**. Except as disclosed on Schedule 5.13, Seller has obtained and is maintaining and is in compliance with all federal, state and local governmental licenses, permits, franchises, orders, exemptions, variances, waivers, authorizations, certificates, consents, rights, privileges and applications therefor (the "**Governmental Authorizations**") that are presently necessary or required for the operation of the Seller Operated

Assets as currently operated (excluding those required under Environmental Laws). All such Governmental Authorizations are in full force and effect and there are no violations of such Governmental Authorizations that would (or could with notice or lapse of time) result in their termination or revocation.

Section 5.14 **Consents and Preferential Purchase Rights**. Except as disclosed in Schedule 5.14, no interest of Seller in an Asset is subject to any (a) Preferential Right (or any part thereof) or (b) Required Consent of any Third Party to the sale and conveyance of Seller's interest in the Assets as provided for in this Agreement (except for Customary Post-Closing Consents).

Section 5.15 **Environmental Matters**. Except as disclosed on Schedule 5.15, (a) to Seller's knowledge, the Seller Operated Assets are, and the operation of the Seller Operated Assets has been and currently is, in compliance in all material respects with the provisions and requirements of all applicable Environmental Laws; (b) there are no pending proceedings, and to knowledge of Seller, there are no threatened proceedings, relating to an alleged Environmental Liability or breach of Environmental Laws on or with respect to the Seller Operated Assets, and Seller has not received any written notice from a Governmental Body of any environmental claim, demand, filing or investigation relating to the Seller Operated Assets or written notice from a Governmental Body of any alleged or actual Environmental Liabilities or violation or non-compliance with any Environmental Law or of non-compliance with the terms or conditions of any environmental permits, arising from, based upon, associated with or related to the Seller Operated Assets or the ownership or operation of any thereof, except for prior instances of non-compliance that have been fully and finally resolved to the satisfaction of all Governmental Bodies with jurisdiction over such matters or Environmental Liabilities that have been fully satisfied; and (c) Seller has not entered into or is subject to any agreement, consent, order, decree or judgment of any Governmental Body that is based on any violations of Environmental Laws and that relates to the current or future use of any Seller Operated Assets. The representation and warranty in this Section 5.15 constitutes the only representation and warranty with respect to Environmental Laws, Environmental Liabilities the release or threatened release of materials into the environment or protection of the environment, natural resources, threatened or endangered species, or health and no other representation or warranty appearing in this Agreement shall be construed to cover Environmental Laws, Environmental Liabilities, the release or threatened release of materials into the environment or protection of the environment, natural resources, threatened or endangered species, or health.

Section 5.16 **Leases**. Except as set forth on Schedule 5.16: (a) Seller has not received any written notice from a lessor of a Lease of any alleged default or breach under any such Lease by Seller or its Affiliates or, to Seller's knowledge, by any other Person that is a party to such Lease; and (b) no royalty owner has requested to perform or, to Seller's knowledge, is currently performing, an audit regarding the payment of any royalties under the Leases or any similar payment.

Section 5.17 **Wells**. With respect to the Seller Operated Assets, except as set forth on Schedule 5.17, (a) no Well is subject to penalties on allowables because of any overproduction or any other violation of Laws; (b) there are no Wells that have been plugged and abandoned in a manner that does not comply with applicable Laws; and (c) with respect to the Properties, there are currently no obligations, whether under Laws or Contracts, and Seller has not received notice or demand from any Governmental Body or Third Party, to plug any Wells, dismantle any facilities, or close any pits and restore or remediate the surface around such Wells, facilities, or pits. All currently producing Wells and Equipment operated by Seller are in an operable state of repair adequate to maintain normal operations in accordance with past practices of Seller, ordinary wear and tear excepted. Schedule 5.17 contains a true and complete list of the status of the Payout Balance as of the Effective Time for each Well operated by Seller.

Section 5.18 **Suspense Funds**. Schedule 5.18 lists all funds held in suspense by Seller or its Affiliates (including the Person last known by Seller to be the appropriate payee and the reason such payments are being held in suspense) as of the Effective Time that are attributable to the Seller Operated Assets.

Section 5.19 **Imbalances**. Schedule 5.19 sets forth all Imbalances associated with the Seller Operated Assets as of the Effective Time.

Section 5.20 **Bankruptcy**. There are no bankruptcy, reorganization or receivership proceedings pending, being contemplated by or, to Seller's knowledge, threatened in writing against Seller or any Affiliate of Seller. Seller is not insolvent.

Section 5.21 **Pipeline Systems**. The Pipeline Systems (a) comply in all material respects with all applicable Laws, (b) are free and clear of liens and encumbrances (other than Permitted Encumbrances), and (c) are in an operable state of repair adequate to maintain normal operations in accordance with past practices, ordinary wear and tear excepted.

ARTICLE 6

REPRESENTATIONS AND WARRANTIES OF PURCHASER

Purchaser represents and warrants to Seller the following:

Section 6.1 **Existence and Qualification**. Purchaser is duly organized, validly existing and in good standing under the Laws of the state of Texas and is duly qualified to do business in Texas. Purchaser has all requisite power and authority to own and operate the Assets and to carry on its business as now conducted.

Section 6.2 **Power**. Purchaser has the requisite power to enter into and perform this Agreement and consummate the transactions contemplated by this Agreement.

Section 6.3 **Authorization and Enforceability**. The execution, delivery and performance of this Agreement, and the performance of the transactions contemplated hereby, have been duly and validly authorized by all necessary action on the part of Purchaser. This Agreement has been duly executed and delivered by Purchaser (and all documents required hereunder to be executed and delivered by Purchaser at Closing will be duly executed and delivered by Purchaser) and this Agreement constitutes, and at the Closing such documents will constitute, the valid and binding obligations of Purchaser, enforceable in accordance with their terms except as such enforceability may be limited by applicable bankruptcy or other similar Laws affecting the rights and remedies of creditors generally as well as to general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at Law).

Section 6.4 **No Conflicts**. The execution, delivery and performance of this Agreement by Purchaser, and the transactions contemplated by this Agreement, will not (a) violate any provision of the limited partnership agreement or other governing or charter documents of Purchaser, (b) result in a material default (with due notice or lapse of time or both) or the creation of any lien or encumbrance, or give rise to any right of termination, cancellation or acceleration under any of the terms, conditions or provisions of any promissory note, bond, mortgage, indenture, loan or similar financing instrument to which Purchaser is a party or which affects Purchaser's assets, (c) violate in any material respect any judgment, order, ruling, or decree applicable to Purchaser as a party in interest or (d) violate in any material respect any Laws applicable to Purchaser or any of its assets (except for rights to consent by, required notices to, and filings with or other actions by Governmental Bodies where the same are not required prior to the assignment of oil and gas interests).

Section 6.5 **Liability for Brokers' Fees**. Seller shall not directly or indirectly have any responsibility, liability or expense, as a result of undertakings or agreements of Purchaser, for brokerage fees, finder's fees, agent's commissions or other similar forms of compensation in connection with this Agreement or any agreement or transaction contemplated hereby.

Section 6.6 **Litigation**. As of the date of the execution of this Agreement, there are no actions, suits or proceedings pending, or to Purchaser's knowledge, threatened in writing before any Governmental Body against Purchaser or any subsidiary of Purchaser which are reasonably likely to materially impair Purchaser's ability to promptly and fully perform its obligations under this Agreement.

Section 6.7 **Financing**. Purchaser has sufficient cash, available lines of credit or other sources of immediately available funds (in United States dollars) to enable it to pay the Closing Payment to Seller at the Closing.

Section 6.8 **Independent Investigation**. Purchaser (a) is sophisticated in the evaluation, purchase, ownership and operation of oil and gas properties and related facilities and is aware of the risks associated with the purchase, ownership and operation of such properties and facilities, (b) is capable of evaluating, and hereby acknowledges that it has so evaluated, the merits and risks of the Assets, ownership and operation thereof and its obligations hereunder, and (c) is able to bear the economic risks associated with the Assets, ownership and operation thereof and its obligations hereunder. In making its decision to enter into this Agreement and to consummate the transactions contemplated hereby, Purchaser (i) has relied or shall rely solely on its own independent investigation and evaluation of the Assets and the advice of its own legal, Tax, economic, environmental, engineering, geological and geophysical advisors and the express provisions of this Agreement and acknowledges and agrees that, except for the express representations, warranties, covenants and remedies provided in this Agreement, (A) it has not been induced by and has not relied upon any representations, warranties or statements, whether express or implied, made at any time by Seller or any of its directors, officers, shareholders, employees, Affiliates, controlling persons, agents, advisors or representatives or any other Person, whether or not any such representations, warranties or statements were made in writing or orally, (B) neither Seller nor any of its directors, officers, shareholders, employees, Affiliates, controlling persons, agents, advisors or representatives or any other Person makes or has made any representation or warranty, either express or implied, as to the accuracy or completeness of any of the information provided or made available to Purchaser or its directors, officers, employees, Affiliates, controlling persons, agents or representatives, including any information, document or material provided or made available, or statements made or provided to Seller (including its directors, officers, employees, Affiliates, controlling persons, agents or representatives) in connection with the transactions contemplated by this Agreement, including without limitation, any such information contained in or provided in "data rooms," management presentations or supplemental due diligence information provided by Seller or discussions or access to management of Seller; and (C) the information referred to in (B) above may include certain projections, estimates and other forecasts and plans and that there are uncertainties inherent in attempting to make such projections, estimates and other forecasts and plans and Purchaser is familiar with such uncertainties and takes full responsibility for making its own evaluation of the adequacy and accuracy of all such projections, estimates and other forecasts and plans and any use or reliance by Purchaser on such information referred to in (B) above is (or the projections, estimates and other forecasts and plans that may be contained therein) at Purchaser's sole risk; (ii) without limiting Purchaser's rights and remedies herein, has satisfied or shall satisfy itself through its own due diligence as to the environmental and physical condition of and contractual arrangements and other matters affecting the Assets; and (iii) agrees to the fullest extent permitted by Law that neither Seller nor any of its directors, officers, employees, Affiliates, controlling persons, agents or representatives shall have any liability or responsibility whatsoever to Purchaser or its directors, officers, employees, Affiliates, controlling persons, agents or representatives on any basis (including in contract or tort, under Federal or state securities laws or otherwise) resulting from the distribution to Purchaser or Purchaser's use of any of the information referred to in clause (i)(B) above. Purchaser acknowledges and affirms as of the Closing Date that (i) it has completed and relied solely upon its own independent investigation, verification, analysis and evaluation of the Assets and the express provisions of this Agreement, (ii) made all such reviews and inspections of the Assets as it has deemed necessary or appropriate and (iii) except for the express representations, warranties, covenants and remedies provided in this Agreement, it is acquiring the Assets on an as-is, where-is basis with all faults, and has not relied upon any other representations, warranties, covenants or statements of Seller in entering into this Agreement.

Section 6.9 **Bankruptcy**. Except for claims or matters related to the bankruptcy case of Penn Virginia Corporation and its subsidiaries commenced under Case No. 16-32395 on May 12, 2016 and concluded on September 12, 2016, for which the United States Bankruptcy Court for the Eastern District of Virginia retains jurisdiction, there are no bankruptcy, reorganization or receivership proceedings pending against, being contemplated by, or, to Purchaser's knowledge, threatened, in writing, against Purchaser or any Affiliate of Purchaser. Purchaser is not insolvent.

Section 6.10 **Qualification**. Purchaser shall be, at Closing, qualified to own and assume operatorship of the Assets in all jurisdictions where the Assets to be transferred to it are located, and the consummation of the transactions contemplated in this Agreement will not cause Purchaser to be disqualified as such an owner or operator. To the extent required by applicable Law, as of the Closing, Purchaser has, and will continue to maintain, all bonds and any other surety instruments as may be required by, and in accordance with, such state or federal regulations governing the ownership and operation of the Assets.

Section 6.11 **Consents**. Except for (a) consents and approvals for the assignment of the Assets to Purchaser that are customarily and lawfully obtained after the assignment of properties similar to the Assets and (b) any consents that Seller is required to obtain under this Agreement or otherwise, there are no consents, approvals or other restrictions on assignment applicable to Purchaser that Purchaser is obligated to obtain or furnish, including requirements for consents from Third Parties to any assignment (in each case), that would be applicable in connection with the consummation of the transactions contemplated by this Agreement or the performance and observance of the covenants and obligations of Purchaser.

Section 6.12 **Knowledge**. As of the Execution Date, Purchaser does not have any knowledge of an actual breach (or any fact, condition or circumstance that could reasonably be considered to constitute or could reasonably be considered to give rise to a breach) of any representation or warranty of Seller hereunder.

ARTICLE 7

COVENANTS OF THE PARTIES

Section 7.1 **Access**. Between the date of execution of this Agreement and continuing until the Closing Date, Seller will give Purchaser and its representatives reasonable access to Seller's offices and the Records, including the right to copy, at Purchaser's expense, the Records in Seller's possession, for the sole purpose of conducting an investigation of the Assets, but only to the extent that Seller may do so without violating any applicable Law or obligations to any Third Party and to the extent that Seller has authority to grant such access without breaching any restriction binding on Seller for which Seller has not, after commercially reasonable efforts without the payment of any money or fees (with respect to which Purchaser has not agreed in writing to pay), obtained the permission, consent or waiver applicable to the records affected by applicable Law or Third Party obligations. Such access by Purchaser shall be subject to applicable limitations in Section 4.1 and shall be limited to Seller's normal business hours, and any weekends and after hours requested by Purchaser that can be reasonably accommodated by Seller, and Purchaser's investigation shall be conducted in a manner that minimizes interference with the operation of the Assets. All information obtained by and access granted to Purchaser and its representatives under this Section shall be subject to the terms of Section 7.6 and the confidentiality restrictions set forth in the Confidentiality Agreement.

Section 7.2 **Government Reviews**. Each Party shall in a timely manner (a) make all required filings, if any, with and prepare applications to and conduct negotiations with, each Governmental Body as to which such filings, applications or negotiations are necessary or appropriate for such Party to consummate the transactions contemplated hereby, and (b) provide such information as the other Party each may reasonably request to make such filings, prepare such applications and conduct such negotiations. Each Party shall cooperate with and use all commercially reasonable efforts to assist the other with respect to such filings, applications and negotiations.

Section 7.3 **Notification of Breaches**.

(a) If any of Purchaser's or Seller's representations or warranties is untrue or shall become untrue in any material respect between the date of execution of this Agreement and the Closing Date, or if any of Purchaser's or Seller's covenants or agreements to be performed or observed prior to or on the Closing Date (other than on a specified date) shall not have been so performed or observed in any material respect, but, if such breach of representation, warranty, covenant or agreement shall (if curable) be cured by the Closing (or, if the Closing does not occur, by the Outside Date), then such breach shall be considered not to have occurred for all purposes of this Agreement.

(b) Notwithstanding anything to the contrary contained herein, if Purchaser elects to proceed with Closing with knowledge by Purchaser of any failure of any condition to be satisfied in its favor or the breach of any agreement or covenant by the Seller, then the condition that is unsatisfied or the agreement or covenant that is breached at the Closing Date shall be deemed waived by Purchaser and Purchaser shall be deemed to fully release and forever discharge Seller on account of any and all claims, demands or charges, known or unknown, with respect to such condition, agreement or covenant; provided, however, that any Purchaser Interim Matter shall not be so released or discharged.

(c) Notwithstanding anything to the contrary contained herein, if Seller elects to proceed with Closing with knowledge by Seller of any failure of any condition to be satisfied in its favor or the breach of any agreement or covenant by the Purchaser, then the condition that is unsatisfied or the agreement or covenant that is breached at the Closing Date shall be deemed waived by Seller and Seller shall be deemed to fully release and forever discharge Purchaser on account of any and all claims, demands or charges, known or unknown, with respect to such condition, agreement or covenant; provided, however, that any Seller Interim Matter and/or Excluded Asset shall not be so released or discharged.

Section 7.4 **Operatorship**. Except with respect to the Assets identified on Schedule 7.4, upon reasonable request from Purchaser, at Purchaser's sole cost and expense, for a period of one hundred and eighty (180) days after the Closing Date, Seller will assist Purchaser in Purchaser's efforts to succeed Seller as operator of any Wells included in the Seller Operated Assets. Seller makes no representation and does not warrant or guarantee that Purchaser will succeed in being appointed successor operator. Purchaser shall promptly, following Closing (or earlier to the extent provided under Section 7.13), file and diligently pursue until receipt of any acknowledgement, consent or confirmation by applicable agencies all appropriate or required forms, applications, permit transfers, declarations, guarantees, or bonds or other financial support with federal and state agencies relative to its assumption of operatorship. Except with respect to the Assets identified on Schedule 7.4, for all Seller Operated Assets, Seller shall execute and deliver to Purchaser, on forms to be prepared by Purchaser and acceptable to Seller, and Purchaser shall promptly file, the applicable forms transferring operatorship of such Seller Operated Assets to Purchaser.

Section 7.5 **Operation of Business**.

(a) Except (i) as set forth on Schedule 7.5, (ii) as may be required to deal with an emergency, (iii) for expenditures or operations set forth on Schedule 5.9, (iv) as required under a Material Contract or (v) as otherwise consented to in writing by Purchaser, which consent shall not be unreasonably withheld, conditioned or delayed, until the Closing, Seller (a) will own the Assets, and operate the Seller Operated Assets, in the ordinary course consistent with past practices, applicable Laws, the Leases and the Contracts, (b) with respect to the Seller Operated Assets, will not commit to any single operation, or series of related operations, reasonably anticipated by Seller to require future capital expenditures by the owner of the Assets in excess of **$100,000** (net to Seller's interest) or make any capital expenditures related to the Assets in excess of **$100,000** (net to Seller's interest), (c) will not terminate, amend, execute or extend any Material Contracts except for any Material Contracts set forth on Schedule 5.8, (d) will maintain its current insurance coverage on the Assets, if any, presently furnished by nonaffiliated Third Parties in the amounts and of the types presently in force, (e) will use commercially reasonable efforts to maintain in full force and effect all Leases, (f) will maintain all material Governmental Authorizations necessary for the ownership or operation of the Assets as currently operated, (g) will not transfer, farmout, sell, hypothecate, encumber or otherwise dispose of any Assets except for sales and dispositions of Hydrocarbon production and Equipment made in the ordinary course of business consistent with past practices, (h) will not, without Purchaser's prior consent, not to be unreasonably withheld, conditioned or delayed, become or permit itself to be deemed a non-consenting party to any operation proposed by a Third Party (excluding any Affiliates of Purchaser) with respect to any Property and (i) will not commit to do any act prohibited by the foregoing clauses (a)-(h). Purchaser's approval of any action restricted by this Section 7.5 shall be considered granted within five (5) Business Days (unless a shorter time is reasonably required by the circumstances and such shorter time is specified in Seller's written notice) of Seller's notice to Purchaser requesting such consent unless Purchaser notifies Seller to the contrary during that period. In the event of an emergency, Seller may take such action as a prudent operator would take and shall notify Purchaser of such action promptly thereafter.

(b) Notwithstanding anything to the contrary contained in this Agreement, with respect to any Asset for which Seller is not the operator, Seller shall not be deemed to have breached or otherwise violated any of its covenants or agreements contained in this Agreement that are applicable to such Assets as a result of an action or inaction of a Third Party operator so long as Seller exercises commercially reasonable efforts to attempt to cause any Third Party operator of such Assets to comply with such covenant or agreement.

(c) Purchaser acknowledges that Seller may own an undivided interest in certain of the Assets and Purchaser agrees that the acts or omissions of the other working interest owners who are not affiliated with Seller shall not constitute a violation of the provisions of this Article 7 nor shall any action required by a vote of working interest owners constitute such a violation so long as Seller has voted its interest in a manner consistent with the provisions of this Article 7.

(d) Notwithstanding anything to the contrary contained in this Agreement, until the earlier to occur of termination of this Agreement pursuant to Article 10 and the Closing, should Seller not wish to participate in any operation properly proposed by Purchaser or its Affiliates with respect to any Property pursuant to the applicable Contract to which such Property is subject, Seller shall give Purchaser written notice thereof no later than five (5) Business Days prior to the conclusion of the timeframes set forth in such Contract; and Seller shall not be obligated to participate in any such operation unless Seller receives from Purchaser, no later than three (3) Business Days prior to the date when a decision with respect to such operation is required to be made by Seller under such Contract, the written election of Purchaser (i) to require Seller to participate in such operation and (ii) to pay all Property Costs of Seller with respect to such operation. If Purchaser provides such written election, Seller shall make an election to participate in such operation in accordance with such Contract, and (A) Purchaser shall be responsible for all Property Costs associated therewith and (B) pursuant to and as set forth in the applicable Contract for which such election was made, Purchaser shall be entitled to collect out of any revenues attributable to the applicable operation the penalty, if any, that Seller, as nonconsenting party, would have suffered under the applicable Contract, with such penalty to be paid and/or received in the same manner as such penalty would have been paid to and/or received thereunder by the consenting parties to such operation.

Section 7.6 **Indemnity Regarding Access**. Purchaser, on behalf of itself and the Purchaser Indemnitees, hereby releases and agrees to indemnify, defend and hold harmless all Seller Indemnitees and the other owners of interests in the Assets from and against any and all claims, liabilities, losses, costs and expenses (including court costs, expert fees and reasonable attorneys' fees) attributable to personal injuries, death, or property damage, to the extent arising out of or relating to Purchaser's access to the Assets or Seller's offices, the Records and other related activities or information prior to the Closing by Purchaser Indemnitees (in each case, pursuant to this Agreement), EVEN IF CAUSED IN WHOLE OR IN PART BY THE NEGLIGENCE (WHETHER SOLE, JOINT OR CONCURRENT), STRICT LIABILITY OR OTHER LEGAL FAULT OF ANY INDEMNIFIED PERSON, EXCEPT TO THE EXTENT ARISING FROM THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE SELLER INDEMNITEES OR ANY PARTY SEEKING INDEMNIFICATION UNDER THIS SECTION 7.6.

Section 7.7 **Other Preferential Rights**.

(a) Should a Third Party fail to exercise its Preferential Right as to any portion of the Assets prior to Closing and the time for exercise or waiver has not yet expired, or in the event such Third Party has exercised its Preferential Right prior to Closing but the transfer with respect to the applicable Property has not been consummated as of Closing, subject to the remaining provisions of this Section 7.7, such Assets shall be included in the transaction at Closing, such Preferential Right to purchase shall be a Permitted Encumbrance hereunder, and the following procedures shall be applicable. Purchaser shall satisfy all such Preferential Right obligations of Seller to such holders and shall indemnify and hold harmless all Seller Indemnitees from and against any and all claims, liabilities, losses, damages, costs and expenses (including court costs, expert fees and reasonable attorney's fees) in connection therewith, and Purchaser shall be entitled to receive (and Seller hereby assigns to Purchaser all of Seller's rights to) all proceeds, received from such holders in connection with such Preferential Rights.

(b) Prior to Closing, should any Third Party bring any suit, action or other proceeding seeking to restrain, enjoin or otherwise prohibit the consummation of the transactions contemplated hereby in connection with a claim to enforce Preferential Rights, the Assets or portion thereof subject to such suit, action or other proceeding shall be excluded from the Assets transferred at Closing and the Purchase Price shall be reduced by the Allocated Value of such excluded Assets or portions thereof. Promptly after the suit, action or other proceeding is dismissed or settled or a judgment is rendered in favor of Seller, as applicable, Seller shall sell to Purchaser, and Purchaser shall purchase from Seller, all such Assets or portions thereof not being sold to the Third Party for a Purchase Price equal to the Allocated Value of such Assets or portions thereof, adjusted as provided in Section 2.2.

Section 7.8 **Tax Matters**.

(a) Subject to the provisions of Section 12.3, Seller shall (i) be responsible for all Asset Taxes related to the ownership or operation of the Assets that are attributable to any taxable period, or portion thereof, that ends at or prior to the Effective Time and (ii) indemnify and hold harmless Purchaser from and against such Asset Taxes (to the extent not already paid by Seller to Purchaser pursuant to Section 7.8(c) or borne by Seller as a result of the adjustment to Purchase Price pursuant to Section 2.2(a)(viii). Purchaser shall (i) be responsible for all other Asset Taxes related to the ownership or operation of the Assets. and (ii) indemnify and hold harmless Seller from and against such Assets Taxes (to the extent not already paid by Purchaser to Seller pursuant to Section 7.8(c) or borne by Purchaser as a result of the adjustment to Purchase Price pursuant to Section 2.2(a)(xii)). For purposes of determining these allocations and the allocations described in Section 2.2, (i) Asset Taxes that are attributable to the severance or production of Hydrocarbons (other than such Asset Taxes described in clause (iii), below) shall be allocated to the period in which the severance or production giving rise to such Asset Taxes occurred, (ii) Asset Taxes that are based upon or related to sales or receipts or imposed on a transactional basis (other than such Asset Taxes described in clause (i) or (iii)), shall be allocated to the period in which the transaction giving rise to such Asset Taxes occurred, and (iii) Asset Taxes that are ad valorem, property or other Asset Taxes imposed on a periodic basis pertaining to a taxable period beginning before and ending after the Effective Time shall be allocated between the portion of such taxable period ending immediately prior to the Effective Time and the portion of such taxable period beginning at the Effective Time by prorating each such Asset Tax based on the number of days in the applicable taxable period that occur before the date on which the Effective Time occurs, on the one hand, and the number of days in such taxable period that occur on or after the date on which the Effective Time occurs, on the other hand. For purposes of clause (iii) of the preceding sentence, the period for such Asset Taxes shall begin on the date on which ownership of the applicable Assets gives rise to liability for the particular Asset Tax and shall end on the day before the next such date.

(b) Regardless of which Party is responsible for Asset Taxes pursuant to Section 7.8(a), Seller shall handle payment to the appropriate Governmental Body of all Asset Taxes related to the ownership or operation of the Assets which are required to be paid prior to Closing (and shall file all Tax Returns with respect to such Asset Taxes); provided, that to the extent such Asset Taxes relate to the periods from and after the Effective Time, as determined pursuant to Section 7.8(a), such payment shall be on behalf of Purchaser, and promptly following the Closing Date, following Seller's request, Purchaser shall pay to Seller any such Asset Taxes (but only to the extent that such amounts have not already been accounted for under Section 2.2). Purchaser shall handle payment to the appropriate Governmental Body of all Asset Taxes related to the ownership or operation of the Assets which are required to be paid after Closing (and shall file all Tax Returns with respect to such Asset Taxes); provided, that in the event that Seller is required by applicable Law to file a Tax Return with respect to such Asset Taxes after the Closing Date which includes all or a portion of a Tax period for which Purchaser is liable for such Asset Taxes, following Seller's request, Purchaser shall promptly pay to Seller all such Asset Taxes allocable to the period or portion thereof beginning at or after the Effective Time (but only to the extent that such amounts have not already been accounted for under Section 2.2).

(c) If Seller or Purchaser (or an Affiliate of Seller or Purchaser) receives a refund of any Taxes (whether by payment, credit offset or otherwise, with any interest thereon) covered by Section 7.8(a) that are paid by and required to be borne by the other Party, the Party that received (or whose Affiliate received) such refund shall promptly (but no later than thirty (30) days after receipt) remit payment to such other Party of an amount equal to the refund amount, with any interest thereon, less expenses incurred in obtaining such refund, including all relevant documentation. Each Party shall cooperate with the other and its Affiliates (at the request of such other Party or its Affiliates) in order to take all reasonably necessary steps to claim any refund to which it is entitled. Purchaser agrees to notify Seller promptly following the discovery of a right to claim any refund to which Seller is entitled and upon receipt of any such refund. In the event a Party has paid a refund to the other Party pursuant to this Section 7.8(c) and is subsequently required to repay such refund to any Governmental Body, upon written request, the Party that had received a payment under this Section 7.8(c) shall promptly repay such amount to the Party required to repay the refund to the Governmental Body.

(d) Except to the extent required by applicable Laws, Purchaser shall not and shall not permit its Affiliates to amend any Tax Return with respect to Taxes for which Seller is liable under Section 7.8(a). Any Tax Return prepared by Purchaser for a taxable period, or portion thereof, beginning before the Effective Time shall (except as otherwise required by applicable Laws) be prepared in accordance with Seller's prior practice and shall not be filed without Seller's written consent (not to be unreasonably withheld, conditioned or delayed) after providing Seller a copy thereof reasonably in advance of the due date for filing such Tax Returns. In the event that Seller is required by applicable Law to file any Tax Return with respect to Taxes for which Purchaser is responsible hereunder, Seller shall prepare and timely file such Tax Return but shall not file such Tax Return without Purchaser's written consent (not to be unreasonably withheld, conditioned or delayed) after providing

Purchaser a copy thereof reasonably in advance of the due date for filing such Tax Return. If Seller or Purchaser disputes any item on a Tax Return described in this Section 7.8(d), it shall notify the other Party of such disputed item (or items) and the basis for its objection. The Parties shall act in good faith to resolve any such dispute prior to the date on which the relevant Tax Return is required to be filed. Purchaser and Seller shall each provide the other with all information reasonably necessary to prepare any Tax Return described in this Section 7.8(d).

(e) After the Closing, Purchaser shall notify Seller in writing within five (5) days of the receipt of the notice of any proposed assessment or commencement of any Asset Tax audit or administrative or judicial proceeding and of any Asset Tax demand or claim on Purchaser or any of its Affiliates that, if determined adversely to the taxpayer or after the lapse of time, could reasonably be grounds for indemnification by Seller; provided, that failure to timely provide such notice shall not affect the right of Purchaser's indemnification hereunder, except to the extent Seller is prejudiced by such delay or omission. Such notice shall contain factual information describing the asserted Asset Tax liability in reasonable detail and shall include copies of any notice or other document received from any Governmental Body in respect of any such asserted Asset Tax liability. Seller shall control any proceeding with respect to any Asset Taxes or Tax Returns (" **Tax Audit** ") for any item relating to a Tax for which Seller is reasonably likely to be solely responsible pursuant to Section 7.8(a). Neither Purchaser nor Seller shall settle any such Tax Audit in a way that would adversely affect the other Party without the other Party's written consent, which consent the other Party shall not unreasonably withhold, delay or condition. Purchaser and Seller shall each provide the other with all information reasonably necessary to conduct a Tax Audit with respect to Asset Taxes or the transactions contemplated by this Agreement. For the avoidance of doubt, the provisions of this Section 7.8(e) (and not the provisions of Section 11.3) shall exclusively govern the Parties' rights and obligations with respect to Tax Audits.

(f) If, prior to Closing, Seller has paid on behalf of other working interest owners, royalty interest owners, overriding royalty interest owners and other interest owners in the Assets, ad valorem, property, severance, production and similar Taxes imposed on the ownership of the Assets or the production of Hydrocarbons produced from such Assets for Tax periods or portions thereof after the Effective Time (such amounts, "**Post-Effective Time Tax Advances** ") and has not recouped such Post-Effective Time Tax Advances before the Closing Date from such working interest owners, royalty interest owners, overriding royalty interest owners and other interest owners in the Assets, Purchaser shall, at Seller's written request, use its commercially reasonable efforts to take such actions requested by Seller, at Seller's expense, to recoup the Post-Effective Time Tax Advances from such other working interest owners, royalty interest owners, overriding royalty interest owners and other interest owners in such Assets and shall promptly remit any such recovered Post-Effective Time Tax Advance amounts to Seller.

(g) Purchaser and Seller agree that either or both of Seller and Purchaser may elect to treat the acquisition or sale of the Assets as an exchange of like-kind property under

Section 1031 of the Code (an "**Exchange**") to the extent permitted by applicable Law; provided that the Closing shall not be delayed by reason of the Exchange. Upon request, each Party agrees to use reasonable efforts to cooperate with the other Party in the completion of such an Exchange including an Exchange subject to the procedures outlined in Treasury Regulation Section 1.1031(k)-1 and/or Internal Revenue Service Revenue Procedure 2000-37. Each of Seller and Purchaser shall have the right at any time prior to Closing to assign all or a part of its rights under this Agreement to a qualified intermediary (as that term is defined in Treasury Regulation Section 1.1031(k)-1(g)(4)(iii)) or an exchange accommodation titleholder (as that term is defined in Internal Revenue Service Revenue Procedure 2000-37) to effect an Exchange. Each Party acknowledges and agrees that neither an assignment of a Party's rights under this Agreement nor any other actions taken by a Party or any other Person in connection with the Exchange shall release either Party from, or modify, any of its liabilities and obligations (including indemnity obligations to each other) under this Agreement, and neither Party makes any representations as to any particular tax treatment that may be afforded to the other Party by reason of such assignment or any other actions taken in connection with the Exchange. The Party electing to treat the acquisition or sale of the Assets as an Exchange shall be obligated to pay all additional costs incurred hereunder as a result of the Exchange, and in consideration for the cooperation of the other Party, the Party electing Exchange treatment shall agree to pay all costs associated with the Exchange and to indemnify and hold the other Party, its Affiliates, and their respective former, current and future partners, members, shareholders, owners, officers, directors, managers, employees, agents and representatives harmless from and against any and all Damages arising out of, based upon, attributable to or resulting from the Exchange or transactions or actions taken in connection with the Exchange that would not have been incurred by the other Party but for the electing Party's Exchange election.

Section 7.9 **Special Warranty of Title**.

(a) The Conveyance shall contain a covenant of Seller to warrant and defend Defensible Title to the Properties after Closing from and against the lawful claims of Third Parties arising by, through or under Seller, but not otherwise (the "**Special Warranty**"). All claims in respect of the Special Warranty must be brought under Section 11.2(c)(iv) and are subject to the survival period set forth in Section 11.4(a).

(b) Notwithstanding anything to the contrary in this Agreement, Seller shall have no liability for breach of the Special Warranty for matters for which and to the extent Purchaser had knowledge prior to the Title Claim Date that such matters constituted a Title Defect hereunder and failed to assert the same under this Agreement prior to the Title Claim Date.

Section 7.10 **Suspended Proceeds**. Seller shall transfer and remit to Purchaser, in the form of an adjustment to the Purchase Price, all Suspended Proceeds. Purchaser shall be solely responsible for the proper distribution of such Suspended Proceeds to the Person or Persons which or who are entitled to receive payment of the same.

Section 7.11 **Further Assurances**. After Closing, Seller and Purchaser each agrees to take such further actions and to execute, acknowledge and deliver all such further documents as are reasonably requested by the other Party for carrying out the purposes of this Agreement or of any document delivered pursuant to this Agreement.

Section 7.12 **Change of Name**. Unless otherwise authorized by Seller in writing, as promptly as practicable, but in any case within thirty (30) days after the Closing Date, Purchaser shall eliminate the name "Hunt Oil" and any variants thereof from the Assets acquired pursuant to this Agreement and, except with respect to such grace period for eliminating existing usage, shall have no right to use any Marks belonging to Seller or any of its Affiliates.

Section 7.13 **Replacement of Bonds; Letters of Credit and Guarantees**.

(a) Purchaser acknowledges that none of the bonds, letters of credit and guarantees, if any, posted by Seller or its Affiliates with any Governmental Bodies and/or relating to the Assets, including those set forth in Schedule 7.13(a) (the "**Governmental Bonds**") are to be transferred to Purchaser. On or before Closing, Purchaser shall obtain, or cause to be obtained in the name of Purchaser, replacements for such Governmental Bonds to the extent such replacements are necessary (i) for Purchaser's ownership of the Assets, and (ii) to permit the cancellation of the Governmental Bonds posted by Seller and/or any Affiliate of Seller with respect to the Assets. In addition, at or prior to Closing, Purchaser shall deliver to Seller evidence of the posting of bonds or other security with all applicable Governmental Bodies meeting the requirements of such Governmental Bodies to own and, if applicable, operate the Assets.

(b) At Seller's request, Purchaser shall cooperate with Seller in order to cause Seller and its Affiliates to be released, as of the Closing Date, from all guarantees, performance bonds, letters of credit, escrow accounts and other forms of financial assurance previously put in place by Seller with Third Parties that are not Governmental Bodies in connection with its ownership and operation of the Assets and that are set forth in Schedule 7.13(b) (the "**Guarantees**"). Without limiting the foregoing, if required by a counterparty to any Guarantee, Purchaser shall, and, if applicable, shall cause its Affiliates to, provide, effective as of the Closing Date or such later date as may be required by such counterparty, substitute guarantee or similar arrangements for all post-Closing periods covered by the Guarantees, which guarantee or similar arrangements shall (i) constitute a type of security, and (ii) be provided by a party whose creditworthiness is, in each case, equivalent to or better than that required by the counterparty to such Guarantee. In the event that any counterparty to any such Guarantee does not release Seller or any of its Affiliates or in the event that any Governmental Body does not permit the cancellation of any Governmental Bond posted by Seller and/or any Affiliate of Seller with respect to the Assets, then, from and after Effective Time, Purchaser shall indemnify Seller or any Affiliate of Seller, as applicable, against all amounts thereafter incurred by Seller or any Affiliate of Seller, as applicable, under such Guarantee or such Governmental Bond (and all costs incurred in connection with such Guarantee or such Governmental Bond) if applicable to the Assets acquired by Purchaser. Notwithstanding anything to the contrary contained in this

Agreement, any cash placed in escrow by Seller or any Affiliate of Seller pursuant to the Guarantees must be returned to Seller as soon as practicable and shall be deemed an Excluded Asset for all purposes hereunder.

Section 7.14 **Audits and Filings**.

(a) Seller acknowledges that Purchaser and its Affiliates may be required to include statements of revenues and direct operating expenses and other financial information relating to the Assets for one or more years or interim periods ending on or prior to the Closing (collectively, the "**Financial Statements**"), and that such Financial Statements may be required to be audited or reviewed in accordance with GAAP and may need to comply with the requirements of the Securities Exchange Commission for inclusion or incorporation by reference into one or more registration statements, reports or other documents (collectively, "**SEC Documents**") required to be filed by Purchaser or its Affiliates under the Securities Act of 1933, as amended (the "**Securities Act**"), the Securities Exchange Act of 1934, as amended (the " **Exchange Act**"), and the rules set forth in Regulation S-X, or other rules promulgated thereunder or in an offering memorandum relating to a private placement of securities exempt from registration under the Securities Act ("**Offering Document**"). From and after the Execution Date, Seller shall, shall cause its Affiliates to, and shall use commercially reasonable efforts to cause its accountants and counsel to, cooperate with Purchaser, its Affiliates and their respective agents, advisors and representatives in preparing and obtaining the Financial Statements to the extent that Seller or such other Persons has such information available or can obtain such information using commercially reasonable efforts. Further, from and after the Execution Date and following reasonable advance notice from Purchaser to Seller, Seller shall, shall cause its Affiliates to, and shall use commercially reasonable efforts to cause its accountants and counsel to, make available during normal business hours to Purchaser and its Affiliates and their agents, advisors and representatives reasonable access to any and all books, records, information and documents that are attributable to the Assets in any of Seller's or any of its Affiliates' possession or control if reasonably required by Purchaser or its Affiliates in connection with the creation and audit or review of the Financial Statements. Purchaser shall be responsible, and obligated to promptly reimburse Seller, for any and all reasonable costs and expenses incurred by Seller or its Affiliates to the extent associated with preparing and obtaining the Financial Statements pursuant to this Section 7.14 and otherwise complying with the provisions of this Section 7.14.

(b) To the extent reasonably requested by Purchaser, Seller shall use its commercially reasonable efforts to obtain representation letters and similar documents (in each case, in form and substance customary for representation letters provided to external audit firms by management of a company whose financial statements are the subject of an audit or review used in filings of acquired company financial statements under the Exchange Act) from applicable personnel of Seller and its Affiliates as may be required in connection with the preparation and audit or review of the Financial Statements or delivery of a "comfort letter" for a securities offering by Purchaser or its Affiliates and solely to the extent related to the Assets; provided, that Purchaser shall provide customary indemnity for any officer or employee of Seller or its Affiliates executing any such representation letter. To the extent requested by Purchaser, Seller shall use its commercially reasonable efforts to request that each independent audit firm that audits or reviews the Financial Statements provide consents necessary for the inclusion or incorporation by reference of the Financial Statements in any SEC Document or any Offering Document in which the Financial Statements are required to be included or incorporated.

(c) All of the information provided by Seller or its Affiliates pursuant to this Section 7.14 is given without any representation or warranty, express or implied, and no Seller Indemnitee shall have any liability or responsibility with respect thereto.

(d) For a period of three (3) years following the Closing Date, Seller shall, and shall cause its respective Affiliates to, retain all books, records, information and documents in their or their Affiliates' possession that are necessary to prepare and audit the Financial Statements, except to the extent originals or copies thereof are transferred to Purchaser in connection with Closing.

Section 7.15 **Tax Partnership Matters**

ARTICLE 8

CONDITIONS TO CLOSING

Section 8.1 **Conditions of Seller to Closing**. The obligations of Seller to consummate the transactions contemplated by this Agreement are subject, at the option of Seller, to the satisfaction on or prior to Closing of each of the following conditions:

(a) Representations. The representations and warranties of Purchaser set forth in Article 6 shall be true and correct as of the date of this Agreement and as of the Closing Date as though made on and as of the Closing Date (other than representations and warranties that refer to a specified date, which need only be true and correct on and as of such specified date), except for such breaches, if any, as would not individually have a Material Adverse Effect (provided, that to the extent such representation or warranty is qualified by its terms by materiality or Material Adverse Effect, such qualification in its terms shall be inapplicable for purposes of this Section and the Material Adverse Effect qualification contained in this Section 8.1(a) shall apply in lieu thereof);

(b) Performance. Purchaser shall have performed and observed, in all material respects, all covenants and agreements to be performed or observed by it under this Agreement prior to or on the Closing Date;

(c) Pending Litigation. No suit, action or other proceeding by any Governmental Body seeking to restrain, enjoin or otherwise prohibit the consummation of the transactions contemplated by this Agreement shall be pending before any Governmental Body;

(d) Deliveries. Purchaser shall have delivered to Seller duly executed counterparts of the Conveyances and the other documents and certificates to be delivered by Purchaser under Section 9.3;

(e) Title Defects, Casualty or Condemnation and Environmental Liabilities . The aggregate amount of (i) the sum of all Title Defect Amounts for actual Title Defects covered by Section 3.4(d)(i) or (ii) (excluding Preferential Rights treated as Title Defects under Section 3.5), less the sum of all Title Benefit Amounts for actual Title Benefits, as determined under Article 3, plus (ii) the sum of all adjustments to the Purchase Price for Environmental Liabilities covered by Section 4.4(a)(i) or (ii), plus (iii) the aggregate amount of the Allocated Values of all Properties excluded from the Properties to be conveyed to Purchaser at Closing pursuant to Section 3.6 shall not exceed an amount equal to **20%** of the Purchase Price; and

(f) Payment. Purchaser shall be ready, willing and able to pay the Closing Payment.

Section 8.2 **Conditions of Purchaser to Closing**. The obligations of Purchaser to consummate the transactions contemplated by this Agreement are subject, at the option of Purchaser, to the satisfaction on or prior to Closing of each of the following conditions:

(a) Representations. The representations and warranties of Seller set forth in Article 5 shall be true and correct as of the date of this Agreement and as of the Closing Date as though made on and as of the Closing Date (other than representations and warranties that refer to a specified date, which need only be true and correct on and as of such specified date), except for such breaches, if any, as would not individually have a Material Adverse Effect (provided, that to the extent such representation or warranty is qualified by its terms by materiality or Material Adverse Effect, such qualification in its terms shall be inapplicable for purposes of this Section and the Material Adverse Effect qualification contained in this Section 8.2(a) shall apply in lieu thereof);

(b) Performance. Seller shall have performed and observed, in all material respects, all covenants and agreements to be performed or observed by it under this Agreement prior to or on the Closing Date;

(c) Pending Litigation. No suit, action or other proceeding by any Governmental Body seeking to restrain, enjoin or otherwise prohibit the consummation of the transactions contemplated by this Agreement shall be pending before any Governmental Body;

(d) Deliveries. Seller shall be ready, willing and able to deliver to Purchaser duly executed counterparts of the Conveyances and the other documents and certificates to be delivered by Seller under Section 9.2; and

(e) Title Defects, Casualty or Condemnation and Environmental Liabilities . The aggregate amount of (i) the sum of all Title Defect Amounts for actual Title Defects covered by Section 3.4(d)(i) or (ii) (excluding Preferential Rights treated as Title Defects under Section 3.5), less the sum of all Title Benefit Amounts for actual Title Benefits, as determined under Article 3, plus (ii) the sum of all adjustments to the Purchase Price for Environmental Liabilities covered by Section 4.4(a)(i) or (ii), plus (iii) the aggregate amount of the Allocated Values of all Properties excluded from the Properties to be conveyed to Purchaser at Closing pursuant to Section 3.6 shall not exceed an amount equal **20%** of the Purchase Price.

ARTICLE 9

CLOSING

Section 9.1 **Time and Place of Closing**.

(a) Consummation of the purchase and sale transaction as contemplated by this Agreement (the "**Closing**"), shall, unless otherwise agreed to in writing by Purchaser and Seller, take place at the offices of Seller at 1900 N Akard St, Dallas, TX 75201, at 10:00 a.m. local time, on the earlier to occur of (i) March 1, 2018 (the "**Target Closing Date**") or (ii) if all conditions in Article 8 to be satisfied prior to Closing have not yet been satisfied or waived on such date, as soon as thereafter as such conditions have been satisfied or waived, subject to the rights of the parties under Article 10.

(b) The date on which the Closing occurs is herein referred to as the " **Closing Date**."

Section 9.2 **Obligations of Seller at Closing**. At the Closing, upon the terms and subject to the conditions of this Agreement, Seller shall deliver or cause to be delivered to Purchaser the following:

(a) the Conveyance, in sufficient duplicate originals to allow recording in all appropriate jurisdictions and offices, duly executed by Seller;

(b) the Preliminary Settlement Statement, duly executed by Seller, in accordance with Section 9.4(a);

(c) to the extent applicable assignments, on appropriate forms, of state and of federal leases comprising portions of the Assets, duly executed by Seller;

(d) to the extent required under any law or Governmental Body, Seller and Purchaser shall deliver federal and state change of operator forms designating Purchaser as the operator of the Properties currently operated by Seller;

(e) letters-in-lieu of division or transfer orders covering the Assets that are prepared and provided by Purchaser and reasonably satisfactory to Seller to reflect the transactions contemplated hereby, duly executed by Seller;

(f) duly executed and acknowledged (where applicable) releases and terminations of any mortgages, deeds of trust, security interests, and other arrangements (with the exception of Memorandums of Operating Agreements and similar documents filed of record in the ordinary course for the purpose of providing notice to Third Parties of the liens and security interests provided for therein) substantially equivalent thereto put in place by Seller or its Affiliates and burdening the Assets, in sufficient counterparts to facilitate recording in each county in which the Assets are located, as applicable, or (for terminations of financing statements) filing with the Secretary of State in the State where Seller is organized;

(g) a certificate duly executed by an authorized officer of Seller, dated as of Closing, certifying on behalf of Seller that the conditions set forth in Sections 8.2(a) and 8.2(b) have been fulfilled; and

(h) an executed statement described in Treasury Regulation §1.1445-2(b)(2) certifying that Seller is not a foreign person within the meaning of the Internal Revenue Code of 1986, as amended;

(i) the Transition Services Agreement, duly executed by Seller; and

(j) any other agreements, instruments and documents that are required by other terms of this Agreement to be executed and/or delivered at Closing or reasonably necessary to effectuate the transactions contemplated by this Agreement.

Section 9.3 **Obligations of Purchaser at Closing**. At the Closing, upon the terms and subject to the conditions of this Agreement, Purchaser shall deliver or cause to be delivered to Seller the following:

(a) a wire transfer of the Closing Payment in same-day funds;

(b) the Preliminary Settlement Statement, duly executed by Purchaser;

(c) the Conveyance, duly executed by Purchaser, in sufficient duplicate originals to allow recording in all appropriate jurisdictions and offices;

(d) to the extent set forth on Schedule 7.13(a), copies of all bonds, letters of credit and guarantees required to be obtained by Purchaser under Section 7.13 or other written evidence that Purchaser is not required under Section 7.13 to obtain such items;

(e) to the extent required under any law or Governmental Body, Seller and Purchaser shall deliver federal and state change of operator forms designating Purchaser as the operator of the Properties currently operated by Seller;

(f) letters-in-lieu of division and transfer orders covering the Assets, duly executed by Purchaser;

(g) a certificate by an authorized officer of Purchaser, dated as of Closing, certifying on behalf of Purchaser that the conditions set forth in Sections 8.1(a) and 8.1(b) have been fulfilled;

(h) the Transition Services Agreement, duly executed by Purchaser; and

(i) any other agreements, instruments and documents that are required by other terms of this Agreement to be executed and/or delivered at Closing or reasonably necessary to effectuate the transactions contemplated by this Agreement.

Section 9.4 **Closing Payment and Post-Closing Purchase Price Adjustments** .

(a) Not later than five (5) Business Days prior to the Closing Date, Seller shall prepare and deliver to Purchaser, based upon the best information available to Seller, acting in good faith, a preliminary settlement statement (along with reasonable supporting information and calculations) estimating the Adjusted Purchase Price after giving effect to all Purchase Price adjustments set forth in Section 2.2, the Deposit, and any amounts placed in the Escrow Account pursuant to Section 3.4(c) (the "**Preliminary Settlement Statement**"). In the event that Purchaser objects to the Preliminary Settlement Statement and Seller and Purchaser cannot come to a resolution with respect to Purchaser's objection, Seller's Preliminary Settlement Statement (with any such modifications agreed by the Parties) shall be used for the purposes of Closing and the estimate delivered in accordance with this Section 9.4(a) shall constitute the dollar amount to be paid by Purchaser to Seller at the Closing (the "**Closing Payment**").

(b) No earlier than sixty (60) days after the Closing but not later than ninety (90) days following the Closing Date, Seller shall prepare, with Purchaser's cooperation, and deliver to Purchaser a statement (the "**Final Settlement Statement**") setting forth the final calculation of the Adjusted Purchase Price and showing the calculation of each adjustment, based, to the extent possible on actual credits, charges, receipts and other items before and after the Effective Time and taking into account (x) adjustments provided for in this Agreement, and (y) any amounts held in and/or released from the Escrow Account pursuant to Section 3.4(c) and Section 4.4(c). Seller shall at Purchaser's request supply reasonable documentation available to support any credit, charge, receipt or other item. As soon as reasonably practicable but not later than the thirtieth (30th) day following receipt of Seller's statement hereunder, Purchaser shall deliver to Seller a written report containing any changes that Purchaser proposes be made to such Final Settlement Statement; provided that, except for any such changes timely delivered by Purchaser, the Final Settlement Statement shall be deemed agreed and final. The Parties shall undertake to agree on the final statement of the Adjusted Purchase Price no later than one hundred thirty (130) days after the Closing Date. In the event that the Parties cannot agree on the Adjusted Purchase Price within one hundred thirty (130) days after the Closing, such determination will be automatically referred to an independent expert of the Parties' choosing with at least ten (10) years of oil and gas accounting experience for arbitration (the "**Independent Expert**"). If the Parties are unable to agree upon an Independent Expert, then such Independent Expert shall be selected by any Federal District Court Judge or State District Court Judge in Houston, Texas. The Independent Expert shall conduct the arbitration proceedings in Houston, Texas in accordance with the Commercial Arbitration Rules of the American Arbitration Association, to the extent such rules do not conflict with the terms of this Section. Seller and Purchaser shall each present to the Independent Expert, with a simultaneous copy to the other Party, a single written statement of its position on the Adjusted Purchase Price, together with a copy of this Agreement and any supporting material that such Party desires to furnish, not later than ten (10) Business Days after appointment of the Independent Expert. The Independent Expert's determination shall be made within thirty (30) days after submission of the matters in dispute and shall be final and binding on both Parties, without right of appeal. In determining the proper amount of any adjustment to the Purchase Price, the Independent Expert shall accept Seller's position or Purchaser's position with respect to each disputed matter, and the Independent Expert shall not increase the Purchase Price more than the increase proposed by Seller nor decrease the Purchase Price more than the decrease proposed by Purchaser with respect to each such matter, as applicable. The Independent Expert shall act as an expert for the limited purpose of determining the specific disputed matters submitted by either Party and may not award damages or penalties to either Party with respect to any matter. Each Party shall bear its own legal fees and other costs of presenting its case. Each Party shall bear one-half of the costs and expenses of the Independent Expert. Within ten (10) days after the date on which the Parties or the Independent Expert, as applicable, finally determines the disputed matters, (i) Purchaser shall pay to Seller the amount by which the Adjusted Purchase Price exceeds the Closing Payment or (ii) Seller shall pay to Purchaser the amount by which the Closing Payment exceeds the Adjusted Purchase Price, as applicable. Any post-closing payment pursuant to this Section 9.4 shall bear interest from the Closing Date to the date of payment at the Agreed Interest Rate.

(c) All payments made or to be made hereunder to Seller shall be by electronic transfer of immediately available funds to the account of Seller pursuant to the wiring instructions reflected in Schedule 9.4(c) or as separately provided in writing. All payments made or to be made hereunder to Purchaser shall be by electronic transfer of immediately available funds to a bank and account specified by Purchaser in writing to Seller.

ARTICLE 10

TERMINATION

Section 10.1 **Termination**. Subject to Section 10.2, this Agreement may be terminated: (a) at any time prior to Closing by the mutual prior written consent of Seller and Purchaser; (b) by Seller or Purchaser if Closing has not occurred on or before the Outside Date; (c) by the Purchaser, if Seller has materially breached this Agreement and such breach causes any of the conditions to Closing set forth in Section 8.2 not to be satisfied as of the Target Closing Date; provided, however, that in the case of a breach that is capable of being cured, the Seller shall have a period of ten (10) days following receipt of such notice to attempt to cure the breach and the termination under this Section 10.1(c) shall not become effective unless the Seller fails to cure such breach prior to the end of such ten (10) day period; (d) by the Seller if the Purchaser has materially breached this Agreement and such breach causes any of the conditions to Closing set forth in Section 8.1 not to be satisfied as of the Target Closing Date; provided, however, that in the case of a breach that is capable of being cured, the Purchaser shall have a period of ten (10) days following receipt of such notice to attempt to cure the breach and the termination under this Section 10.1(d) shall not become effective unless the Purchaser fails to cure such breach prior to the end of such ten (10) day period;

or (e) by Seller if the Purchaser fails to pay the Deposit on or before 5:00 p.m. (Central Time) on the second (2nd) Business Day after the Execution Date; provided, however, that termination under clauses (b), (c), (d) or (e) shall not be effective until the Party electing to terminate has delivered written notice to the other Party of its election to so terminate; provided further, that no Party shall have the right to terminate this Agreement pursuant to clauses (c) or (d) above, if such Party or its Affiliates are at such time in material breach of this Agreement; *provided further*, that a Party shall not have the right to terminate under clause (b) if the Closing has not occurred as a result of the terminating Party's breach of its representations, warranties or covenants in this Agreement.

Section 10.2 **Effect of Termination**. If this Agreement is terminated pursuant to Section 10.1, except as set forth in this Section 10.2 and in Section 10.3, this Agreement shall be of no further force or effect (except for the provisions of this Article 10, Sections 5.6, 6.5, 7.5(d), 7.6, 11.6 (other than clause (b)), 12.2, 12.4, 12.5, 12.6, 12.7, 12.8, 12.9, 12.10, 12.11, 12.12, 12.13, 12.14, 12.15, 12.16, 12.17 and 12.18 and Article 13 (as to definitions used in the other surviving provisions only)), all of which shall continue in full force and effect in accordance with their terms) and Seller shall be free immediately to enjoy all rights of ownership of the Assets and to sell, transfer, encumber or otherwise dispose of the Assets to any Person without any restriction or limitation under this Agreement. Subject to Section 10.3, the termination of this Agreement under Section 10.1(b), 10.1(c), 10.1(d), or 10.1(e) shall not relieve any Party from liability to the other Party at Law or in equity for any failure to perform or observe in any material respect any of its agreements or covenants contained herein which are to be performed or observed at or prior to Closing.

Section 10.3 **Distribution of Deposit Upon Termination**.

(a) If Seller is entitled to terminate this Agreement pursuant to Section 10.1(b) (in the event that Purchaser does not also have the right to terminate under Section 10.1(b)) or 10.1(d) and Seller has performed or is ready, willing and able to perform all of its agreements and covenants contained herein which are to be performed or observed at or prior to Closing, then Seller may elect to:

(i) terminate this Agreement and receive the Deposit from the Escrow Agent (and the Parties shall instruct the Escrow Agent accordingly within five (5) Business Days of such termination) as liquidated damages and as Seller's sole and exclusive remedy for any breach or failure to perform by Purchaser under this Agreement, and all other remedies (except those under Section 7.6 and under the Confidentiality Agreement) are hereby expressly waived by Seller, and upon such termination (A) Seller and Purchaser agree upon the Deposit as liquidated damages due to the difficulty and inconvenience of measuring actual damages and the uncertainty thereof, and Seller and Purchaser agree that such amount would be a reasonable estimate of Seller's loss in the event of any such breach or failure to perform by Purchaser and (B) Seller shall be free immediately to enjoy all rights of ownership of the Assets and to sell, transfer, encumber or otherwise dispose of the Assets to any Person without any restriction or limitation under this Agreement; or

(ii) in lieu of termination of this Agreement, seek specific performance of this Agreement, it being specifically agreed that monetary damages will not be sufficient to compensate Seller if Seller determines the same in its sole discretion. If Seller elects to seek specific performance of this Agreement pursuant to this Section 10.3(a)(ii), (A) the Escrow Agent shall retain the Deposit, until a non-appealable final judgment or award on Seller's claim for specific performance is rendered, at which time the Deposit shall be applied as provided in Section 2.4 of this Agreement and (B) if Seller is not granted specific performance, Seller shall have the right to terminate this Agreement as set forth in Section 10.3(a)(i).

(b) If Purchaser is entitled to terminate this Agreement pursuant to Section 10.1(c) and Purchaser has performed or is ready, willing and able to perform all of its agreements and covenants contained herein which are to be performed or observed at or prior to Closing, then Purchaser may elect to:

(i) terminate this Agreement, receive the Deposit from the Escrow Agent (and the Parties shall instruct the Escrow Agent accordingly within five (5) Business Days of such termination) and seek actual damages against Seller not to exceed the amount of the Deposit, and Seller shall be free immediately to enjoy all rights of ownership of the Assets and to sell, transfer, encumber or otherwise dispose of the Assets to any Person without any restriction or limitation under this Agreement; or

(ii) in lieu of termination of this Agreement, Purchaser shall be entitled to seek specific performance of this Agreement, it being specifically agreed that monetary damages will not be sufficient to compensate Purchaser if Purchaser determines the same in its sole discretion. If Purchaser elects to seek specific performance of this Agreement pursuant to this Section 10.3(b)(ii), (A) the Escrow Agent shall retain the Deposit, until a non-appealable final judgment or award on Purchaser's claim for specific performance is rendered, at which time the Deposit shall be distributed as provided in Section 2.4 of this Agreement or (B) if Purchaser is not granted specific performance, Purchaser shall have the right to terminate this Agreement as set forth in Section 10.3(b)(i).

(c) If this Agreement terminates for reasons other than those set forth in Section 10.3(a), Section 10.3(b) or Section 10.1(e), the Parties shall instruct the Escrow Agent to return the Deposit to Purchaser, free of any claims by Seller or any other Person with respect thereto, within five (5) Business Days of termination, and each Party shall have no further liability hereunder of any nature whatsoever to the other Party, including any liability for Damages (except for the provisions of Sections 5.6, 6.5, 7.6, 10.2 and 12.4 which shall continue in full force and effect in accordance with their terms), and Seller shall be free immediately to enjoy all rights of ownership of the Assets and to sell, transfer, encumber or otherwise dispose of the Assets to any Person without any restriction or limitation under this Agreement.

(d) If this Agreement terminates pursuant to Section 10.1(e), each Party shall have no further liability hereunder of any nature whatsoever to the other Party, including any liability for Damages (except for the provisions of Sections 5.6, 6.5, 7.6, 10.2 and 12.4 which shall continue in full force and effect in accordance with their terms), and Seller shall be free immediately to enjoy all rights of ownership of the Assets and to sell, transfer, encumber or otherwise dispose of the Assets to any Person without any restriction or limitation under this Agreement.

ARTICLE 11

POST-CLOSING OBLIGATIONS; INDEMNIFICATION; LIMITATIONS; DISCLAIMERS AND WAIVERS

Section 11.1 **Receipts**.

(a) Except as otherwise provided in this Agreement, any production from or attributable to the Assets (and all products and proceeds attributable thereto) and any other income, proceeds, receipts and credits attributable to the Assets which are not reflected in the adjustments to the Purchase Price following the final adjustment pursuant to Section 9.4(b) shall be treated as follows: (i) all production from or attributable to the Assets (and all products and proceeds attributable thereto) and all other income, proceeds, receipts and credits earned with respect to the Assets to which Purchaser is entitled under Section 1.4 shall be the sole property and entitlement of Purchaser, and, to the extent received by Seller, Seller shall fully disclose, account for and remit the same to Purchaser in each case within ten (10) days after receipt thereof; and (ii) all production from or attributable to the Assets (and all products and proceeds attributable thereto) and all other income, proceeds, receipts and credits earned with respect to the Assets to which Seller is entitled under Section 1.4 shall be the sole property and entitlement of Seller and, to the extent received by Purchaser, Purchaser shall fully disclose, account for and remit the same to Seller in each case within ten (10) days after receipt thereof.

(b) Notwithstanding any other provisions of this Agreement to the contrary, Seller shall be entitled to retain (and Purchaser shall not be entitled to any decrease to the Purchase Price in respect of) all overhead charges it has collected, billed or which shall be billed later, relating to the Seller Operated Assets for the period from the Effective Time to the date Seller relinquishes operatorship of the applicable Seller Operated Assets, even if after the date of Closing.

Section 11.2 **Assumption and Indemnification**.

(a) Without limiting Purchaser's rights to indemnity under this Article 11 and, if applicable, any indemnity entered into pursuant to Section 3.4(d)(iii) or Section 4.4(a)(v), from and after the Closing, Purchaser shall assume and hereby agrees to timely fulfill, perform, pay and discharge (or cause to be fulfilled, performed, paid or discharged) all of the obligations and liabilities of Seller, known or unknown, with respect to the Assets, regardless of whether such obligations or liabilities arose prior to, on or after the Effective Time, including but not limited to (i) obligations to furnish makeup gas according to the terms of applicable gas sales, gathering or transportation contracts, (ii) gas balancing obligations and other obligations arising from Imbalances, (iii) obligations to pay Property Costs and other costs and expenses attributable to the ownership or operation of the Assets,

(iv) obligations to pay working interests, royalties, overriding royalties and other interests held in suspense, including the Suspended Proceeds, (v) obligations to plug or abandon wells and associated equipment and dismantle structures, or re-plug previously abandoned wells, and to restore and/or remediate the Assets in accordance with applicable agreements, Leases or Laws (including Environmental Laws), (vi) any claims regarding the general method, manner or practice of calculating or making royalty payments (or payments for overriding royalties or similar burdens on production) with respect to the Properties, (vii) to the extent disclosed on Schedule 5.11(b), continuing obligations, if any, under any Contracts or other agreements pursuant to which Seller or its Affiliates purchased or acquired Assets prior to the Closing and (viii) all obligations and liabilities associated with or related to the Exploration Wells (all of said obligations and liabilities, subject to the exclusions below, herein being referred to as the "**Assumed Obligations**"); provided that, notwithstanding anything to the contrary herein, Purchaser shall not assume, and Seller shall retain, all of the Retained Obligations; provided, further that to the extent a Retained Obligation ceases to be a Retained Obligation it shall thereafter be an Assumed Obligation.

(b) If Closing occurs, from and after Closing, except for Damages for which Seller is required to indemnify Purchaser Indemnitees under Section 11.2(c), Purchaser shall indemnify, defend and hold harmless the Seller Indemnitees from and against all Damages incurred or suffered by the Seller Indemnitees to the extent:

(i) caused by, arising out of, resulting from or relating to the Assumed Obligations;

(ii) caused by, arising out of or resulting from Purchaser's breach of any of Purchaser's covenants or agreements that survive the Closing;

(iii) caused by, arising out of or resulting from any breach of any representation or warranty made by Purchaser contained in Article 6 of this Agreement or in the certificate delivered by Purchaser at Closing pursuant to Section 9.3(g); or

(iv) caused by, arising out of or resulting from any claims or actions asserted by Persons (including Governmental Bodies) with respect to (A) any condition affecting any Asset that violates or requires remediation under Environmental Law, (B) any operations conducted on such Asset that violate any Environmental Law or (C) any remediation required for an Asset under any Environmental Law regardless of whether known or unknown, or whether attributable to periods of time before, on or after the Effective Time.

EVEN IF SUCH DAMAGES ARE CAUSED IN WHOLE OR IN PART BY THE NEGLIGENCE (WHETHER SOLE, JOINT OR CONCURRENT), STRICT LIABILITY OR OTHER LEGAL FAULT (EXCEPT FOR THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT) OF SELLER INDEMNITEES.

(c) If Closing occurs, from and after Closing, Seller shall indemnify, defend and hold harmless Purchaser Indemnitees against and from all Damages incurred or suffered by Purchaser Indemnitees to the extent (the "**Seller Indemnity Obligations**"):

(i) caused by, arising out of or resulting from any breach of any of Seller's covenants or agreements that survive the Closing;

(ii) caused by, arising out of or resulting from any breach of any representation or warranty made by Seller contained in Article 5 of this Agreement or in the certificate delivered by Seller at Closing pursuant to Section 9.2(g);

(iii) caused by, arising out of, resulting from or related to the Retained Obligations; or

(iv) caused by, arising out of or resulting from any breach of the Special Warranty.

EVEN IF SUCH DAMAGES ARE CAUSED IN WHOLE OR IN PART BY THE NEGLIGENCE (WHETHER SOLE, JOINT OR CONCURRENT), STRICT LIABILITY OR OTHER LEGAL FAULT (EXCEPT FOR THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT) OF PURCHASER INDEMNITEES.

(d) Notwithstanding anything to the contrary contained in this Agreement, except for the rights of the Parties under Article 10, Section 7.6, and Section 7.8, including breaches of the Special Warranty in the Conveyance, this Section 11.2 contains the Parties' exclusive remedy against each other with respect to breaches of this Agreement, including breaches of the representations and warranties contained in Articles 5 and 6, the covenants and agreements that survive the Closing pursuant to the terms of this Agreement and the affirmations of such representations, warranties, covenants and agreements contained in the certificates delivered by the Parties at Closing pursuant to Sections 9.2(g) or 9.3(g), as applicable. Except for the rights and remedies specifically contained in this Section 11.2 and for the rights of the Parties under Article 10, Section 7.6, and Section 7.8, each Party (on behalf of itself, each of the other Purchaser Indemnitees, in the case of Purchaser, and the Seller Indemnitees, in the case of Seller, and their respective insurers and successors in interest) releases, remises and forever discharges the other Party (including, in the case of Purchaser, the Purchaser Indemnitees, and, in the case of Seller, the Seller Indemnitees) from any and all suits, legal or administrative proceedings, claims, remedies, demands, damages, losses, costs, liabilities, interest, or causes of action whatsoever, in Law or in equity, known or unknown, which such Parties might now or subsequently may have, based on, relating to or arising out of this Agreement, the ownership, use or operation of the Assets, or the condition, quality, status or nature of the Assets, including rights to contribution under CERCLA, as amended, and under other Environmental Laws, breaches of statutory or implied warranties, nuisance or other tort actions, rights to punitive damages and common law rights of contribution, rights under agreements between a Party and any Persons who are Affiliates of such Party (except to the extent any such agreements constitute Contracts), and rights under insurance maintained by a Party or any Person who is an Affiliate of such

Party, EVEN IF CAUSED IN WHOLE OR IN PART BY THE NEGLIGENCE (WHETHER SOLE, JOINT OR CONCURRENT), STRICT LIABILITY OR OTHER LEGAL FAULT (EXCEPT FOR THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT) OF ANY RELEASED PERSON. NOTWITHSTANDING ANYTHING TO THE CONTRARY HEREIN, (I) THE RIGHTS OF EACH PARTY RELATING TO AUDITS UNDER ANY AGREEMENT BETWEEN OR AMONG SELLER OR ITS AFFILIATES ON THE ONE HAND AND PURCHASER OR ITS AFFILIATES ON THE OTHER HAND RELATING TO THE DESIGNATED AREA (INCLUDING ANY SUCH AGREEMENTS WITH THIRD PARTIES) *VIS-À-VIS* THE OTHER PARTY, EXISTING IMMEDIATELY PRIOR TO THE EXECUTION DATE SHALL NOT BE PREJUDICED OR OTHERWISE AFFECTED BY THE PROVISIONS OF THIS AGREEMENT AND (II) PURCHASER SHALL HAVE THE RIGHT TO NET OUT ANY CONSULTANT EXPENSES (FOR WHICH, IF NOT FOR THE TRANSACTIONS CONTEMPLATED HEREBY, SELLER OR ITS AFFILIATES WOULD OTHERWISE BE RESPONSIBLE) INCURRED OR OTHERWISE PAID BY PURCHASER OR ITS AFFILIATES IN CONNECTION WITH ANY SALES AND USE TAX AUDIT FROM ANY AMOUNTS RECOVERED THEREFROM AND PAID TO SELLER.

(e) "**Damages**," for purposes of this Agreement, shall mean the amount of any actual liability, loss, cost, diminution in value, expense, claim, demand, notice of violation, investigation by any Governmental Body, administrative proceeding, payment, charge, obligation, fine, penalty, deficiency, award or judgment incurred or suffered by any Indemnified Party arising out of or resulting from the indemnified matter, including reasonable fees and expenses of attorneys, consultants, accountants or other agents and experts reasonably incident to matters indemnified against, and the costs of investigation and/or monitoring of such matters, and the costs of enforcement of the indemnity; provided, however, that no Person shall be entitled to indemnification under this Section 11.2 for Damages that constitute consequential, special or indirect damages suffered by Purchaser, or any punitive damages, except to the extent a Person is required to pay such damages to a Third Party that is not an Indemnified Party.

(f) Notwithstanding any other provision of this Agreement or a document to be delivered hereto to the contrary, any claim for indemnity to which a Seller Indemnitee or Purchaser Indemnitee is entitled must be asserted by and through Seller or Purchaser, as applicable.

Section 11.3 **Indemnification Actions**. Except as otherwise provided in Section 7.8(e), all claims for indemnification under Section 11.2 shall be asserted and resolved as follows:

(a) For purposes of this Article 11, the term "**Indemnifying Party**" when used in connection with particular Damages shall mean the Party having an obligation to indemnify another Person or Persons with respect to such Damages pursuant to this Article 11, and the term "**Indemnified Party**" when used in connection with particular Damages shall mean the Person or Persons having the right to be indemnified with respect to such Damages by another Party pursuant to this Article 11, subject to Section 11.2(f).

(b) To make a claim for indemnification under Article 11, an Indemnified Party shall notify the Indemnifying Party of its claim under this Section 11.3, including the specific details of and specific basis under this Agreement for its claim (the "**Claim Notice**"). In the event that the claim for indemnification is based upon a claim by a Third Party against the Indemnified Party (a "**Third Party Claim**"), the Indemnified Party shall provide its Claim Notice promptly after the Indemnified Party has actual knowledge of the Third Party Claim and shall enclose a complete copy of all papers (if any) served with respect to the Third Party Claim; provided, that the failure of any Indemnified Party to give notice of a Third Party Claim as provided in this Section 11.3 shall not relieve the Indemnifying Party of its obligations under Section 11.2 except to the extent such failure materially prejudices the Indemnifying Party's ability to defend against the Third Party Claim. In the event that the claim for indemnification is based upon an inaccuracy or breach of a representation, warranty, covenant or agreement, the Claim Notice shall specify the representation, warranty, covenant or agreement which was inaccurate or breached.

(c) In the case of a claim for indemnification based upon a Third Party Claim, the Indemnifying Party shall have thirty (30) days from its receipt of the Claim Notice to notify the Indemnified Party whether it elects to assume the defense of the Indemnified Party against such Third Party Claim under this Article 11. If the Indemnifying Party does not notify the Indemnified Party within such thirty (30) day period regarding whether the Indemnifying Party elects to assume the defense of the Indemnified Party, it shall be deemed to have denied its obligation to provide such indemnification hereunder. The Indemnified Party is authorized, prior to and during such thirty (30)-day period, to file any motion, answer or other pleading that it shall deem necessary or appropriate to protect its interests or those of the Indemnifying Party.

(d) If the Indemnifying Party elects to assume the defense of the Indemnified Party, it shall have the right and obligation to diligently defend, at its sole cost and expense, the Third Party Claim. The Indemnifying Party shall have full control of such defense and proceedings, including any compromise or settlement thereof, subject to the remainder of this Section 11.3(d). If requested by the Indemnifying Party, the Indemnified Party agrees to cooperate in contesting any Third Party Claim which the Indemnifying Party elects to contest; provided that the Indemnified Party shall not be required to bring any counterclaim or cross-complaint against any Person. The Indemnified Party may participate in, but not control, any defense or settlement of any Third Party Claim controlled by the Indemnifying Party pursuant to this Section 11.3(d). An Indemnifying Party shall not, without the written consent of the Indemnified Party settle any Third Party Claim or consent to the entry of any judgment with respect thereto that (i) does not result in a final, non-appealable, resolution of the Indemnified Party's liability with respect to the Third Party Claim (including, in the case of a settlement, an unconditional written release of the Indemnified Party from all further liability in respect of such Third Party Claim) or results in any monetary liability of the Indemnified Party or (ii) may materially and adversely affect the Indemnified Party (other than as a result of money damages covered by the indemnity).

(e) If the Indemnifying Party does not admit its obligation or admits its obligation but fails to diligently defend or settle the Third Party Claim, then the Indemnified Party shall have the right to defend against the Third Party Claim (at the sole cost and expense of the Indemnifying Party, if the Indemnified Party is entitled to indemnification hereunder), with counsel of the Indemnified Party's choosing, subject to the right of the Indemnifying Party to admit its obligation to indemnify the Indemnified Party and assume the defense of the Third Party Claim at any time prior to settlement or final, non-appealable determination thereof.

(f) In the case of a claim for indemnification not based upon a Third Party Claim, the Indemnifying Party shall have thirty (30) days from its receipt of the Claim Notice to (i) cure or remedy the Damages complained of, (ii) admit its obligation to provide indemnification with respect to such Damages or (iii) dispute the claim for such Damages. If the Indemnifying Party does not notify the Indemnified Party within such thirty (30)-day period that it has cured or remedied the Damages or that it admits the claim for such Damages, the Indemnifying Party shall be conclusively deemed to have disputed the claim for indemnification hereunder.

(g) Any claim for indemnity under Section 11.2 by any Affiliate, officer, director, partner, employee or agent must be brought and administered by the applicable Party to this Agreement. No Indemnified Party other than Seller and Purchaser shall have any rights against either Seller or Purchaser under the terms of Section 11.2 except as may be exercised on its behalf by Purchaser or Seller, as applicable, pursuant to this Section 11.3(g).

Section 11.4 **Limitation on Actions**.

(a) Except for the Fundamental Representations, all representations and warranties of Seller and Purchaser contained herein shall survive until the date that is twelve (12) months from and after the Closing Date and expire thereafter. The Fundamental Representations shall survive the Closing until the expiration of 60 days after the applicable statute of limitations. The Special Warranty (together with the indemnification rights with respect thereto) will survive for a period of forty-eight (48) months from and after the Closing Date. The covenants and other agreements of Seller and Purchaser set forth in this Agreement to be performed on or before Closing shall expire six (6) months following the Closing Date and each other covenant and agreement of Seller and Purchaser shall, subject to this Section 11.4, survive the Closing until fully performed in accordance with its terms and expire thereafter. The affirmations of representations, warranties, covenants and agreements contained in the certificate delivered by each Party at Closing pursuant to Sections 9.2(g) and 9.3(g), as applicable, shall survive the Closing as to each representation, warranty covenant and agreement so affirmed for the same period of time that the specific representation, warranty, covenant or agreement survives the Closing pursuant to this Section 11.4, and shall expire thereafter. Representations, warranties, covenants and agreements shall terminate and be of no further force and effect after the respective date of their expiration, after which time no claim may be asserted thereunder by any Person; provided, that there shall be no termination of any bona fide claim timely asserted pursuant to this Section 11.4.

(b) The indemnities in Section 11.2(b)(ii), 11.2(b)(iii), 11.2(c)(i), 11.2(c)(ii) and 11.2(c)(iv) shall terminate as of the termination date of each respective representation, warranty, covenant or agreement that is subject to indemnification, except in each case as to matters (and solely with respect to such matters) for which a specific written claim for indemnity has been delivered to the Indemnifying Party on or before such termination date. Purchaser's indemnities in Sections 7.6, 11.2(b)(i), and 11.2(b)(iv) and Seller's indemnities in Section 11.2(c)(iii) shall continue without time limit.

(c) Notwithstanding anything to the contrary contained elsewhere in this Agreement:

(i) Seller shall not be required to indemnify any Person under Section 11.2(c)(ii) for any individual liability, loss, cost, expense, claim, award or judgment that does not exceed **$125,000**;

(ii) Subject to Section 11.4(c)(i), Seller shall not have any liability for indemnification under Section 11.2(c)(ii) until and unless the aggregate amount of the liability for all Damages for which Claim Notices are timely delivered by Purchaser exceeds a deductible amount equal to **1.75%** of the Purchase Price (the "**Indemnity Deductible**"), after which point Purchaser (or Purchaser Indemnitees) shall be entitled to claim Damages in excess of the Indemnity Deductible;

(iii) Seller shall not be required to indemnify Purchaser and Purchaser Indemnitees under Section 11.2(c)(ii) for aggregate Damages claimed by Purchaser and Purchaser Indemnitees in excess of **15%** of the Purchase Price;

(iv) Seller shall not be required to indemnify any Person under Section 11.2(c) unless Seller has received a timely delivered Claim Notice with respect to such claim at or prior to the expiration of the applicable representation, warranty, covenant or Retained Obligation; and

(v) Solely for purposes of determining the amount of any Damages that are the subject matter of a claim for indemnification under Section 11.2(c)(ii), each representation and warranty herein that is qualified by materiality or a specified dollar amount will be read without regard and without giving effect to such qualifier.

(d) Seller and Purchaser acknowledge that after the Closing the payment of money, as limited by the terms of this Agreement, shall be adequate compensation for breach of any representation, warranty, covenant or agreement contained in this Agreement or for any other claim arising in connection with or with respect to the transactions contemplated in this Agreement. As the payment of money shall be adequate compensation, Purchaser and Seller waives any right to rescind this Agreement or any of the transactions contemplated hereby.

(e) Notwithstanding anything in this Agreement to the contrary, in no event shall any Purchaser Indemnitees be entitled to assert the breach of any representation or warranty of Seller in this Agreement or any related document or any certificate delivered pursuant hereto or thereto or assert any claim hereunder for any such breach, if Purchaser or its Affiliates knew, prior to the Closing Date, of any fact, condition or circumstance that would give rise to such claim or cause such representation or warranty to not be true and correct as of the Execution Date and/or the Closing Date; provided, however, that this Section 11.4(e) shall not apply to any Purchaser Interim Matter.

(f) Notwithstanding anything in this Agreement to the contrary, in no event shall any Seller Indemnitees be entitled to assert the breach of any representation or warranty of Purchaser in this Agreement or any related document or any certificate delivered pursuant hereto or thereto or assert any claim hereunder for any such breach, if Seller or its Affiliates knew, prior to the Closing Date, of any fact, condition or circumstance that would give rise to such claim or cause such representation or warranty to not be true and correct as of the Execution Date and/or the Closing Date; provided, however, that this Section 11.4(f) shall not apply to any Seller Interim Matter or Excluded Asset.

(g) The limitations in Section 11.4(c)(i)-(iii) shall not apply to the Fundamental Representations.

Section 11.5 **Recording**. As soon as practicable after Closing, Purchaser shall record the Conveyances in the appropriate counties as well as the appropriate governmental agencies and provide Seller with copies of all recorded or approved instruments.

Section 11.6 **Waivers**.

(a) The Parties do not intend that any implied obligation of good faith or fair dealing requires any Party to incur, suffer or perform any act, condition or obligation contrary to the terms of this Agreement or any documents delivered in connection herewith and that it would be unfair, and that they do not intend, to increase any of the obligations of any Party under this Agreement or any documents delivered in connection herewith on the basis of any such implied obligation.

(b) Purchaser acknowledges that plugging, abandonment, removal and restoration obligations for the Assets are material and significant. Purchaser acknowledges that Purchaser has conducted its own investigation and evaluation as to the cost and timing of such obligations and that, other than the representations and warranties set forth in Article 5 of this Agreement, Seller has made no representation or warranty as to the expected cost or timetable for incurring costs of plugging, abandonment, removal and restoration obligations for the Assets. Purchaser acknowledges that Seller is entering into this Agreement in reliance upon Purchaser's agreement to assume the Assumed Obligations and that the assumption of the Assumed Obligations constitutes material agreed consideration to Seller in consideration for the Assets.

(c) It is the intention of the Parties that Purchaser's rights and remedies with respect to this transaction and with respect to all acts or practices of Seller, past, present or future, in connection with this transaction shall be governed by legal principles other than the Texas Deceptive Trade Practices-Consumer Protection Act, Subchapter E of Chapter 17, Sections 17.41 et seq., of the Texas Business and Commerce Code, as amended (the "**DTPA**"). As such, Purchaser hereby waives the applicability of the DTPA to this transaction and any and all duties, rights or remedies that might be imposed by the DTPA, whether such duties, rights and remedies are applied directly by the DTPA themselves or indirectly in connection with other statutes. Purchaser acknowledges, represents and warrants (i) that it is purchasing the goods and/or services covered by this Agreement for commercial or business use; (ii) that it has assets of **$5,000,000** or more according to its most recent financial statement prepared in accordance with GAAP; (iii) that it has knowledge and experience in financial and business matters that enable it to evaluate the merits and risks of a transaction such as this; (iv) that it is represented by legal counsel of its own choosing in seeking or acquiring the goods or services contemplated by this Agreement; and (v) that it is not in a significantly disparate bargaining position with Seller. Purchaser expressly recognizes that the price for which Seller has agreed to perform its obligations under this Agreement has been predicated upon the inapplicability of the DTPA and this waiver of the DTPA. Purchaser further recognizes that Seller, in determining to proceed with the entering into of this Agreement, has expressly relied on this waiver and the inapplicability of the DTPA.

Section 11.7 **Tax Treatment of Indemnification Payments** . The Parties agree that any payments made by one Party to the other Party pursuant to this Article 11 shall be treated for all Tax purposes as an adjustment to the Purchase Price for the Assets unless otherwise required by applicable Law.

ARTICLE 12

MISCELLANEOUS

Section 12.1 **Counterparts**. This Agreement may be executed in counterparts, each of which shall be deemed an original instrument, but all such counterparts together shall constitute but one agreement. Delivery of an executed counterpart signature page by facsimile or electronic transmittal (PDF) is as effective as executing and delivering this Agreement in the presence of other Parties to this Agreement.

Section 12.2 **Notice**. All notices which are required or may be given pursuant to this Agreement shall be sufficient in all respects if given in writing and delivered personally, by facsimile or by registered or certified mail, postage prepaid, as follows:

If to Seller: Hunt Oil Company
1900 N. Akard St.
Dallas, TX 75202
Attention: Travis Armayor

Telephone: (214) 978-8000
Fax: (214) 978-8888
Email: TArmayor@huntoil.com

With a copy to: Hunt Oil Company
1900 N. Akard St.
Dallas, TX 75202
Attention: General Counsel
Telephone: (214) 978-8000
Fax: (214) 978-8888
Email: mmonroe@huntoil.com

If to Purchaser: Penn Virginia Oil & Gas, L.P.
14701 St. Mary's Lane
Suite 275
Houston, Texas 77079
Attention: John A. Brooks, Chief Executive Officer
Email: John.Brooks@pennvirginia.com

With a copy to: Penn Virginia Oil & Gas, L.P.
14701 St. Mary's Lane
Suite 275
Houston, Texas 77079
Attention: Katie Ryan, Vice President, Chief Legal Counsel & Corporate Secretary
Email: Katie.Ryan@pennvirginia.com

With a copy to (which shall not constitute notice):

Gibson, Dunn & Crutcher LLP
1221 McKinney
Houston, Texas 77010
Attention: Justin T. Stolte
Email: JStolte@gibsondunn.com

Either Party may change its address for notice by notice to the other in the manner set forth above. All notices shall be deemed to have been duly given (i) when physically delivered in person to the Party to which such notice is addressed, (ii) when transmitted to the Party to which such notice is addressed by confirmed facsimile transmission, or (iii) at the time of receipt by the Party to which such notice is addressed. Notwithstanding the foregoing, delivery by Seller or Purchaser (as applicable) of a Title Defect Notice, Title Benefit Notice or statement of the Purchase Price under Section 9.4, or a response to any of the foregoing, shall be deemed to have been duly given to the other Party when transmitted via email (with hard copy mailed or shipped by U.S. Mail or commercial delivery service, respectively, on the day such email is transmitted) to the address(es) of the representative(s) of such Party named above that were previously furnished to the delivering

Party upon an affirmative reply by email by the intended recipient that such email was received (provided that, for the avoidance of doubt, an automated response from the email account or server of the intended recipient shall not constitute an affirmative reply) or, if earlier, the delivery confirmation date of such mailed or shipped hard copy.

Section 12.3 **Sales or Use Tax, Recording Fees, and Similar Taxes and Fees** . Purchaser shall (i) bear any sales, use, excise, real property transfer, gross receipts, goods and services, registration, capital, documentary, stamp or transfer Taxes, recording fees and similar Taxes and fees incurred and imposed upon, or with respect to, the property transfers or other transactions contemplated hereby ("**Transfer Taxes** ") and (ii) bear, and reimburse Seller for, any costs reasonably incurred in connection with any audit, examination or other proceeding by or with any taxing authority relating to the determination of the amount of such Transfer Taxes. Seller will determine, and Purchaser agrees to cooperate with Seller in determining, Transfer Taxes, if any, that applicable law requires Seller to collect from Purchaser in connection with the sale of Assets hereunder, and Purchaser agrees to pay any such tax to Seller at Closing; provided, however, that Seller's failure to collect any such Transfer Taxes at Closing shall not absolve Purchaser from Purchaser's responsibility for such Transfer Taxes. If such transfers or transactions are exempt from any such Taxes or fees upon the filing of an appropriate certificate or other evidence of exemption, Purchaser will timely furnish to Seller such certificate or evidence.

Section 12.4 **Expenses**. Except as otherwise provided in Section 12.3, all expenses incurred by Seller in connection with or related to the authorization, preparation or execution of this Agreement, the Conveyance and the Exhibits and Schedules hereto and thereto, and all other matters related to the Closing, including all fees and expenses of counsel, accountants and financial advisers employed by Seller, shall be borne solely and entirely by Seller, and all such expenses incurred by Purchaser shall be borne solely and entirely by Purchaser.

Section 12.5 **Governing Law and Venue** . This Agreement and the legal relations between the Parties shall be governed by and construed in accordance with the Laws of the State of Texas without regard to principles of conflicts of Law that would direct the application of the Law of another jurisdiction. The venue for any action brought under this Agreement shall be Harris County, Texas.

Section 12.6 **Jurisdiction; Waiver of Jury Trial** . EACH PARTY CONSENTS TO PERSONAL JURISDICTION IN ANY ACTION BROUGHT IN THE UNITED STATES FEDERAL COURTS LOCATED WITHIN HARRIS COUNTY, TEXAS (OR, IF JURISDICTION IS NOT AVAILABLE IN THE UNITED STATES FEDERAL COURTS, TO PERSONAL JURISDICTION IN ANY ACTION BROUGHT IN THE STATE COURTS LOCATED IN HARRIS COUNTY, TEXAS) WITH RESPECT TO ANY DISPUTE, CLAIM OR CONTROVERSY ARISING OUT OF OR IN RELATION TO OR IN CONNECTION WITH THIS AGREEMENT, AND EACH OF THE PARTIES AGREES THAT ANY ACTION INSTITUTED BY IT AGAINST THE OTHER WITH RESPECT TO ANY SUCH DISPUTE, CONTROVERSY OR CLAIM (EXCEPT TO THE EXTENT A DISPUTE, CONTROVERSY, OR CLAIM ARISING OUT OF OR IN RELATION TO OR IN CONNECTION WITH THE DETERMINATION OF A TITLE DEFECT AMOUNT OR TITLE BENEFIT AMOUNT PURSUANT TO SECTION 3.4(H), THE

DETERMINATION OF AN ENVIRONMENTAL DEFECT PURSUANT TO SECTION 4.4(C), OR THE DETERMINATION OF PURCHASE PRICE ADJUSTMENTS PURSUANT TO SECTION 9.4(B) IS REFERRED TO AN EXPERT PURSUANT TO THOSE SECTIONS) WILL BE INSTITUTED EXCLUSIVELY IN THE UNITED STATES FEDERAL COURTS LOCATED WITHIN HARRIS COUNTY, TEXAS (OR, IF JURISDICTION IS NOT AVAILABLE IN THE UNITED STATES FEDERAL COURTS, TO PERSONAL JURISDICTION IN ANY ACTION BROUGHT IN THE STATE COURTS LOCATED IN HARRIS COUNTY, TEXAS). THE PARTIES HEREBY WAIVE TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM BROUGHT BY ANY PARTY AGAINST ANOTHER IN ANY MATTER WHATSOEVER ARISING OUT OF OR IN RELATION TO OR IN CONNECTION WITH THIS AGREEMENT. IN ADDITION, EACH PARTY IRREVOCABLY WAIVES ANY OBJECTION, INCLUDING ANY OBJECTION TO THE LAYING OF VENUE OR BASED ON THE GROUNDS OF FORUM NON CONVENIENS, WHICH IT MAY NOW OR HEREAFTER HAVE TO THE BRINGING OF ANY SUCH ACTION IN THE RESPECTIVE JURISDICTIONS REFERENCED IN THIS SECTION.

Section 12.7 **Captions**. The captions in this Agreement are for convenience only and shall not be considered a part of or affect the construction or interpretation of any provision of this Agreement.

Section 12.8 **Waivers**. Any failure by any Party to comply with any of its obligations, agreements or conditions herein contained may be waived in writing, but not in any other manner, by the Party or Parties to whom such compliance is owed. No waiver of, or consent to a change in, any of the provisions of this Agreement shall be deemed or shall constitute a waiver of, or consent to a change in, other provisions hereof (whether or not similar), nor shall such waiver constitute a continuing waiver unless otherwise expressly provided.

Section 12.9 **Assignment**. Neither Party shall assign all or any part of this Agreement, nor shall any Party assign or delegate any of its rights or duties hereunder, without the prior written consent of the other Party and any assignment or delegation made without such consent shall be void.

Section 12.10 **Entire Agreement**. This Agreement and the documents to be executed hereunder and the Exhibits and Schedules attached hereto, constitute the entire agreement between the Parties pertaining to the subject matter hereof, and supersede all prior agreements, understandings, negotiations and discussions, whether oral or written, of the Parties pertaining to the subject matter hereof.

Section 12.11 **Confidentiality Agreement**. Subject to and upon the occurrence of Closing and as between the Parties hereto only, the Confidentiality Agreement shall be deemed to have terminated; provided, however, the Confidentiality Agreement shall remain in force and effect with respect to the following, each of which shall be considered "Confidential Information" as defined in and under the terms of the Confidentiality Agreement, (a) the existence and terms of this Agreement and any documents or information exchanged between the Parties pursuant hereto (except to the extent the same constitutes an Asset hereunder), (b) any matters made expressly subject to the Confidentiality Agreement pursuant to this Agreement and (c) in the event Purchaser does not acquire all of the Assets in accordance with the terms of this Agreement, then all such Assets that are not so acquired by Purchaser and any information or data related thereto. Further, if the Closing should occur, then from and after Closing the terms and conditions of the Confidentiality Agreement will apply *mutatis mutandis* to Seller and its Affiliates (as if it, and they, were the "Recipient" thereunder) for a period equal to the initial term of the Confidentiality Agreement, it being the intent of the Parties that Seller will treat the "Confidential Information" (as defined therein) in strict confidence for such period after the Closing; provided, however, that Purchaser acknowledges and agrees that Seller and/or its Affiliates have presented information and data that may constitute Confidential Information to other potential purchasers of the Assets and that this sentence shall not apply to and Seller and its Affiliates shall not have any liability with respect to any such disclosures or any disclosures by such other potential purchasers. In the event of a conflict between the Confidentiality Agreement and this Agreement, then as between the Parties hereto the terms and provisions of this Agreement shall prevail.

Section 12.12 **Amendment**. This Agreement may be amended or modified only by an agreement in writing executed by both Parties. No waiver of any right under this Agreement shall be binding unless executed in writing by the Party to be bound thereby.

Section 12.13 **No Third-Party Beneficiaries**. Nothing in this Agreement shall entitle any Person other than Purchaser and Seller to any claims, cause of action, remedy or right of any kind, except the rights expressly provided to the Persons described in Section 11.2(f).

Section 12.14 **Public Announcements**. The Parties acknowledge and agree that no press release or other public announcement, or public statement or comment in response to any inquiry, or other disclosure that is reasonably expected to result in a press release or public announcement, relating to the subject matter of this Agreement shall be issued or made by Seller or Purchaser, or their respective Affiliates, without the joint written approval of Seller and Purchaser (such approval not to be unreasonably withheld, conditioned or delayed); provided, that, a press release or other public announcement, or public statement or comment in response to any inquiry, made without such joint approval shall not be in violation of this Section if it is made, upon advice of counsel, in order for the disclosing Party or any of its Affiliates to comply with applicable Laws or stock exchange rules or regulations and provided it is limited to those disclosures that are required to so comply.

Section 12.15 **Invalid Provisions**. If any provision of this Agreement is held to be illegal, invalid or unenforceable under present or future Laws effective during the term hereof, such provision shall be fully severable; this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof; and the remaining provisions of this Agreement shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance from this Agreement.

Section 12.16 **References**. In this Agreement:

(a) References to any gender includes a reference to all other genders;

(b) References to the singular includes the plural, and vice versa;

(c) Reference to any Article or Section means an Article or Section of this Agreement;

(d) Reference to any Exhibit or Schedule means an Exhibit or Schedule to this Agreement, all of which are incorporated into and made a part of this Agreement; provided that, in the event of conflict between any Exhibit or Schedule and any provision set forth in the body of this Agreement, the provisions set forth in this Agreement shall control to the extent of such conflict;

(e) References to $ or Dollars means the lawful currency of the United States of America;

(f) Unless expressly provided to the contrary, "hereunder," "hereof," "herein" and words of similar import are references to this Agreement as a whole and not any particular Section or other provision of this Agreement;

(g) "Include" and "including" shall mean include or including without limiting the generality of the description preceding such term;

(h) "Shall" and "will" have equal force and effect;

(i) A reference to a writing includes a facsimile or email transmission of it and any means of reproducing of its words in a tangible and permanently visible form;

(j) A reference to any agreement or document (including without limitation a reference to this Agreement) is to the agreement or document as amended, varied, supplemented, novated, or replaced, except to the extent prohibited by this Agreement or that other agreement or document;

(k) A reference to legislation or to a provision of legislation includes a modification or reenactment of it, a legislative provision substituted for it, and a regulation or statutory instrument issued under it;

(l) A reference to any Party to this Agreement or another agreement or document includes the Party's permitted successors and assigns;

(m) If a word or phrase is defined, its other grammatical forms have a corresponding meaning;

(n) No action shall be required of the Parties except on a Business Day, and in the event an action is required on a day which is not a Business Day, such action shall be required to be performed on the next succeeding day which is a Business Day;

(o) All references to "day" or "days" shall mean calendar days unless specified as a "Business Day;"

(p) All accounting terms used and not expressly defined herein have the respective meanings given to them under GAAP;

(q) Any item herein "to the knowledge of Purchaser" (or similarly qualified), including that Purchaser "knew" such as set forth in Section 11.4(e), is limited to matters within the actual knowledge of HARRY QUARLS (Executive Chairman), JOHN A. BROOKS (President and Chief Executive Officer), CHARLOTTE GUIDRY (Manager, Land) or SEAN MAHAFFEY (Manager, HSE); and

(r) "Actual knowledge" for purposes of this Agreement means information actually personally known (i) in the case of Seller, by the Persons set forth on Exhibit C, after reasonable inquiry of those employees of Seller or its Affiliates reporting directly to such Person who would reasonably be expected to have knowledge of the fact, event or circumstance in question and (ii) in the case of Purchaser, by the Persons identified in Section 12.16(q), after reasonable inquiry of those employees of Purchaser or its Affiliates reporting directly to such Person who would reasonably be expected to have knowledge of the fact, event or circumstance in question.

Section 12.17 **Construction**. Each of Seller and Purchaser has had substantial input into the drafting and preparation of this Agreement and has had the opportunity to exercise business discretion in relation to the negotiation of the details of the transaction contemplated hereby. This Agreement is the result of arm's-length negotiations from equal bargaining positions.

Section 12.18 **Limitation on Damages**. NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED HEREIN, NONE OF PURCHASER, SELLER OR ANY OF THEIR RESPECTIVE AFFILIATES OR INDEMNITEES SHALL BE ENTITLED TO EITHER PUNITIVE, SPECIAL, INDIRECT OR CONSEQUENTIAL DAMAGES IN CONNECTION WITH THIS AGREEMENT AND THE TRANSACTIONS CONTEMPLATED HEREBY AND EACH OF PURCHASER AND SELLER, FOR ITSELF AND ON BEHALF OF ITS AFFILIATES AND INDEMNITEES, HEREBY EXPRESSLY WAIVES ANY RIGHT TO PUNITIVE, SPECIAL, INDIRECT OR CONSEQUENTIAL DAMAGES IN CONNECTION WITH THIS AGREEMENT AND THE TRANSACTIONS CONTEMPLATED HEREBY, EXCEPT TO THE EXTENT AN INDEMNIFIED PARTY IS REQUIRED TO PAY PUNITIVE, SPECIAL, INDIRECT OR CONSEQUENTIAL DAMAGES TO A THIRD PARTY THAT IS NOT AN INDEMNIFIED PARTY.

ARTICLE 13

DEFINITIONS

"**Adjusted Purchase Price**" has the meaning set forth in Section 2.1.

"**Affiliates**" with respect to any Person, means any Person that directly or indirectly controls, is controlled by or is under common control with such Person. For purposes of this definition, "control" means the possession, directly or indirectly, of the power, directly or indirectly, to direct or cause the direction of the management or policies of the controlled Person, whether through the ownership of equity interests in or voting rights attributable to the equity interests in such Person, by contract or agency, by the general partner of a Person that is a partnership, or otherwise; and "controls" and "controlled" have meanings correlative thereto.

"**Agreed Interest Rate**" shall mean simple interest computed at the rate of the prime interest rate as published in the Wall Street Journal.

"**Agreement**" has the meaning set forth in the first paragraph of this Agreement.

"**Allocated Value**" has the meaning set forth in Section 2.3(a).

"**Assessment**" has the meaning set forth in Section 4.1.

"**Assets**" has the meaning set forth in Section 1.2.

"**Asset Taxes**" shall mean ad valorem, property, excise, severance, production, sales, use, and similar Taxes based upon or measured by the ownership or operation of the Assets or the production of Hydrocarbons or the receipt of proceeds therefrom, but excluding, for the avoidance of doubt, Income Taxes and Transfer Taxes.

"**Assumed Obligations**" has the meaning set forth in Section 11.2(a).

"**Business Day**" means each calendar day except Saturdays, Sundays, and Federal holidays.

"**CERCLA**" has the meaning set forth in the definition of Environmental Laws.

"**Claim Notice**" has the meaning set forth in Section 11.3(b).

"**Closing**" has the meaning set forth in Section 9.1(a).

"**Closing Date**" has the meaning set forth in Section 9.1(b).

"**Closing Payment**" has the meaning set forth in Section 9.4(a).

"**Code**" means the Internal Revenue Code of the United States.

"**Confidentiality Agreement**" means that certain Confidentiality Agreement dated October 25, 2017, between Seller, as the Disclosing Party, and Purchaser, as the Receiving Party, relating to the Assets.

"**Contracts**" has the meaning set forth in Section 1.2(d).

"**Conveyance**" has the meaning set forth in Section 3.1(b).

"**COPAS**" has the meaning set forth in Section 1.4(b).

“**Copyrights**” means all copyrights and works of authorship in any media (including computer programs, Software, databases and compilations, files, applications, internet site content, documentation, and related items), whether or not registered, copyright registrations, or copyright applications.

“**Cure Period**” has the meaning set forth in Section 3.4(c).

“**Customary Post-Closing Consents**” means the consents and approvals from Governmental Bodies for the assignment (directly or indirectly) of the Assets (or any portion thereof) or the transfer of operations of any of the Wells to Purchaser, in each case, that are customarily obtained after such assignment of properties similar to the Assets or transfer of operations of a well.

“**Damages**” has the meaning set forth in Section 11.2(e).

“**Defensible Title**” has the meaning set forth in Section 3.2(a).

“**Deposit**” has the meaning set forth in Section 2.4.

“**Designated Area**” means the area shown on Exhibit A-4.

“**DTPA**” has the meaning set forth in Section 11.6(c).

“**Effective Time**” has the meaning set forth in Section 1.4(a).

“**Environmental Arbitration Notice**” has the meaning set forth in Section 4.4(c).

“**Environmental Arbitrator**” has the meaning set forth in Section 4.4(c).

“**Environmental Claim Date**” has the meaning set forth in Section 4.3.

“**Environmental Consultant**” has the meaning set forth in Section 4.1.

“**Environmental Defect**” has the meaning set forth in Section 4.3.

“**Environmental Defect Deductible**” has the meaning set forth in Section 4.4(d).

“**Environmental Defect Notice**” has the meaning set forth in Section 4.3.

“**Environmental Laws**” means, as the same have been amended as of the Effective Time, the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9601 et seq. (“**CERCLA**”); the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et seq.; the Federal Water Pollution Control Act, 33 U.S.C. § 1251 et seq.; the Clean Air Act, 42 U.S.C. § 7401 et seq. the Hazardous Materials Transportation Act, 49 U.S.C. § 1471 et seq.; the Toxic Substances Control Act, 15 U.S.C. §§ 2601 through 2629; the Oil Pollution Act, 33 U.S.C. § 2701 et seq.; the Emergency Planning and Community Right-to-Know Act, 42 U.S.C. § 11001 et seq.; and the Safe Drinking Water Act, 42 U.S.C. §§ 300f through 300j; and all Laws as of the Effective Time of any Governmental Body having jurisdiction over the property in question addressing pollution or protection of the environment and all regulations implementing the foregoing. Notwithstanding the foregoing, the phrase "violation of Environmental Laws" and words of similar import used herein shall mean, as to any given Asset, the violation of or failure to meet specific objective requirements or standards that are clearly applicable to such Asset under applicable Environmental Laws where such requirements or standards are in effect as of the Effective Time. The phrase does not include good or desirable operating practices or standards that may be employed or adopted by other oil or gas well operators or recommended by a Governmental Body.

"**Environmental Liabilities**" shall mean any and all environmental response costs (including costs of remediation), Damages, natural resource damages, settlements, consulting fees, expenses, penalties, fines, orphan share, prejudgment and post-judgment interest, court costs, attorneys' fees, and other liabilities incurred or imposed (i) pursuant to any order, notice of responsibility, directive (including requirements embodied in Environmental Laws), injunction, judgment or similar act (including settlements) by any Governmental Body to the extent arising out of any violation of or liability under any Environmental Law which is attributable to the ownership or operation of the Seller Operated Assets prior to the Effective Time or (ii) pursuant to any claim or cause of action by a Governmental Body for damage to natural resources to the extent arising out of any violation of or liability under any Environmental Law to the extent attributable to the ownership or operation of the Seller Operated Assets prior to the Effective Time; provided, that Environmental Liabilities excludes any of the foregoing liabilities to the extent caused by or relating to NORM or otherwise disclosed in any Schedule.

"**Equipment**" has the meaning set forth in Section 1.2(f).

"**Escrow Account**" has the meaning set forth in Section 2.4.

"**Escrow Agent**" means Citibank, National Association.

"**Escrow Agreement**" means the agreement attached hereto as Exhibit D.

"**Exchange**" has the meaning set forth in Section 7.8(g).

"**Exchange Act**" has the meaning set forth in Section 7.14(a).

"**Excluded Assets**" has the meaning set forth in Section 1.3.

"**Execution Date**" has the meaning set forth in the first paragraph of this Agreement.

"**Exploration Wells**" means those wells set forth on Exhibit F.

"**Final Settlement Statement**" has the meaning set forth in Section 9.4(b).

"**Financial Statements**" has the meaning set forth in Section 7.14(a).

"**Fundamental Representations**" means the representations and warranties in Sections 5.2, 5.3, 5.4, 5.5, 5.6, 5.8 and 5.20.

“**G & G Data** ” means any and all geological or geophysical information licensed by Seller.

“**GAAP**” means United States generally accepted accounting principles.

“**Governmental Authorizations**” has the meaning set forth in Section 5.13.

“**Governmental Body**” means any federal, state, local, municipal, or other governments; any governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, police, regulatory or taxing authority or power; and any court or governmental tribunal.

“**Governmental Bonds**” has the meaning set forth in Section 7.13(a).

“**Guarantees**” has the meaning set forth in Section 7.13(b).

“**Hazardous Substances**” means any pollutants, contaminants, toxins or hazardous or extremely hazardous substances, materials, wastes, constituents, compounds, or chemicals that are regulated by, or may form the basis of liability under, any Environmental Laws, including NORM.

“**Hydrocarbons**” means oil, gas, condensate and other gaseous and liquid hydrocarbons or any combination thereof, including scrubber liquid inventory and ethane, propane, isobutene, nor-butane and gasoline inventories (excluding tank bottoms), and sulphur and other minerals extracted from or produced from the foregoing hydrocarbons.

“**Imbalance**” means any over-production, under-production, over-delivery, under-delivery or similar imbalance of Hydrocarbons produced from or allocated to the Assets, regardless of whether such imbalance arises at the platform, wellhead, pipeline, gathering system, transportation system, processing plant or other location.

“**Income Taxes**” shall mean (a) all Taxes based upon, measured by, or calculated with respect to gross or net income, gross or net receipts or profits (including franchise Taxes and any capital gains, alternative minimum, and net worth Taxes, but excluding ad valorem, property, excise, severance, production, sales, use, real or personal property transfer or other similar Taxes), (b) Taxes based upon, measured by, or calculated with respect to multiple bases (including corporate franchise, doing business or occupation Taxes) if one or more of the bases upon which such Tax may be based, measured by, or calculated with respect to is included in clause (a) above, or (c) withholding Taxes measured with reference to or as a substitute for any Tax included in clauses (a) or (b) above.

“**Indemnified Party**” has the meaning set forth in Section 11.3(a).

“**Indemnifying Party**” has the meaning set forth in Section 11.3(a).

“**Indemnity Deductible**” has the meaning set forth in Section 11.4(c)(ii).

“**Independent Expert**” has the meaning set forth in Section 9.4(b).

“**Individual ED Threshold**” has the meaning set forth in Section 4.3.

"**Individual TD Threshold**" has the meaning set forth in Section 3.4(i).

"**Intellectual Property**" means all intellectual property rights arising from or in respect of the following, whether protected, created, or arising under the Laws of the United States or any other jurisdiction: (a) all Patents; (b) all Marks; (c) all Copyrights; (d) all Trade Secrets; and (e) all Software and Technology.

"**Lands**" has the meaning set forth in Section 1.2(a).

"**Law**" or "**Laws**" means all statutes, rules, regulations, ordinances, orders, and codes of Governmental Bodies.

"**Leases**" has the meaning set forth in Section 1.2(a).

"**Lowest Cost Response**" means the response required or allowed under Environmental Laws that cures, remediates, removes or remedies the applicable present condition alleged pursuant to an Environmental Defect Notice at the lowest cost (considered as a whole taking into consideration any material negative impact such response may have on the operations of the relevant Assets and any potential material additional costs or liabilities that may likely arise as a result of such response) sufficient to comply with Environmental Laws as compared to any other response that is required or allowed under Environmental Laws. The Lowest Cost Response shall include taking no action, leaving the condition unaddressed, periodic monitoring or the recording of notices in lieu of remediation, if such responses are allowed under Environmental Laws.

"**Material Adverse Effect**" means any adverse effect on the ownership or operation of the Assets that individually or in the aggregate has or would reasonably be expected to have an adverse effect in an amount that exceeds **$12,900,000** (without taking into account any insurance proceeds or other similar benefits received by a Party with respect to same); provided, however, that "Material Adverse Effect" shall not include any material adverse effects resulting from: (a) changes in general market, economic, financial or political conditions (including changes in commodity prices, fuel supply or transportation markets, interest or rates) in the area in which the Assets are located, the United States or worldwide; (b) changes in Laws or in regulatory policies from and after the date of this Agreement (to the extent generally applying to oil and gas properties located in the region where the Assets are located); (c) changes or conditions resulting from civil unrest or terrorism or acts of God or natural disasters; (d) change or conditions resulting from the failure of a Governmental Body to act or omit to act pursuant to Law; (e) entering into this Agreement or the announcement of the transactions contemplated by this Agreement; (f) changes in conditions or developments generally applicable to the oil and gas industry in the area where the Assets are located; (g) matters that are cured or no longer exist by the earlier of the Closing and the termination of this Agreement, without cost to Purchaser; (h) reclassification or recalculation of reserves in the ordinary course of business; (i) changes in the prices of Hydrocarbons; (j) declines in well performance; and (k) operational issues occurring in the ordinary course of business.

"**Material Contract**" has the meaning set forth in Section 5.11.

“**Marks**” mean all trademarks, trademark applications, trademark registrations, trade names, fictitious business names (d/b/a’s), service marks, service mark applications, service mark registrations, URL’s, domain names, trade dress, and logos.

“**Net Revenue Interest**” has the meaning set forth in Section 3.2(a)(i).

“**Nonconsented Interest**” has the meaning set forth in Section 3.5(b).

“**NORM**” means naturally occurring radioactive material.

“**Offering Document**” has the meaning set forth in Section 7.14(a).

“**Outside Date**” means May 1, 2018.

“**Patents**” means all patents, patent applications, statutory invention registrations, or similar types of protection for inventions and innovations, including reissues, divisions, continuations, continuations in part, and reexaminations thereof.

“**Permitted Encumbrances**” has the meaning set forth in Section 3.3.

“**Party**” or “**Parties**” has the meaning set forth in the Preamble to this Agreement.

“**Payout Balance**” means the status, as of the date of the calculation, of the recovery by Seller or a Third Party of a cost amount specified in the contract relating to a Well out of the revenue from such Well where the Net Revenue Interest of Seller therein will be reduced or increased or Seller’s working interest therein will be reduced or increased when such amount has been recovered.

“**Person**” means any individual, firm, corporation, partnership, limited liability company, joint venture, association, trust, unincorporated organization, government or agency or subdivision thereof or any other entity.

“**Phase I Assessment**” has the meaning set forth in Section 4.1(a).

“**Phase II Assessment**” has the meaning set forth in Section 4.1(b).

“**Phase II Request**” has the meaning set forth in Section 4.1(b).

“**Pipeline Systems**” has the meaning set forth in Section 1.2(g).

“**Post-Effective Time Tax Advances**” has the meaning set forth in Section 7.8(f).

“**Preferential Right**” has the meaning set forth in Section 3.5(a).

“**Preliminary Settlement Statement**” has the meaning set forth in Section 9.4(a).

“**Properties**” and “**Property**” have the meanings set forth in Section 1.2(c).

"**Property Costs**" means (a) all costs attributable to the ownership, development, operation or maintenance of the Assets (including costs of insurance, but excluding lease bonus payments, renewals, extensions or amendments) in the ordinary course of business or the production of Hydrocarbons therefrom, but excluding any Taxes, (b) capital expenditures incurred in the ownership, development, operation and maintenance of the Assets in the ordinary course of business, (c) where applicable, such costs and capital expenditures charged in accordance with the relevant operating agreement, unit agreement, pooling agreement, pre-pooling agreement, pooling order or similar instrument, and (d) overhead costs charged to the Assets under the relevant operating agreement, unit agreement, pooling agreement, pre-pooling agreement, pooling order or similar instrument by unaffiliated third parties; *provided* that "Property Costs" shall exclude, without limitation, liabilities, losses, costs, and expenses attributable to (i) claims, investigations, administrative proceedings or litigation directly or indirectly arising out of or resulting from actual or claimed personal injury or death, property damage or violation of any Law (including private rights or causes of action under any Law), (ii) title claims (including claims that the Leases have terminated), (iii) obligations to plug wells, dismantle facilities, close pits and restore the surface or seabed around such wells, facilities and pits, (iv) obligations to cure, address or remediate any contamination of groundwater, surface water, soil or Equipment under applicable Environmental Laws, (v) obligations to furnish make-up gas according to the terms of applicable gas sales, gathering or transportation contracts, (vi) gas balancing obligations and similar obligations arising from Imbalances, (vii) Asset Taxes, Income Taxes and Transfer Taxes, and (viii) obligations to pay working interests, royalties, overriding royalties or other interests held in suspense.

"**Purchase Price**" has the meaning set forth in Section 2.1.

"**Purchaser**" has the meaning set forth in the first paragraph of this Agreement.

"**Purchaser Indemnitees**" means Purchaser, its Affiliates, and the officers, directors, managers, members, stockholders, general or limited partners, employees, agents, representatives, advisors, subsidiaries, successors and assigns of Purchaser or its Affiliates.

"**Purchaser Interim Matter**" shall mean any matter, solely to the extent related to the Seller Operated Assets, that (i) individually or in the aggregate would not give rise to Purchaser's right to terminate this Agreement pursuant to Section 10.1(c) and (ii) is discovered by Purchaser between the Execution Date and the Closing Date.

"**Purchaser Operated Property Costs**" means those costs and expenses identified on Exhibit G.

"**Records**" has the meaning set forth in Section 1.2(j).

"**Required Consent**" means a consent by a Third Party that, if not obtained prior to the assignment of an Asset, (a) makes the assignment with respect to such Asset void or voidable, (b) terminates Seller's interest in the Asset subject to such consent, or (c) requires the payment of a fee for such consent or assesses a fine or monetary penalty for failure to obtain such consent; provided, however, "Required Consent" does not include any consent which by its terms cannot be unreasonably withheld or any Customary Post-Closing Consent.

"**Retained Obligations**" means any and all of the obligations and liabilities of Seller, known or unknown, arising from, based upon, related to or associated with: (a) Seller's payment, nonpayment or mispayment of all royalties, shut-in royalties, overriding royalties and compensatory royalties attributable to the Seller Operated Assets prior to the Execution Date (other than Suspended Proceeds transferred by Seller to Purchaser pursuant to Section 7.10); (b) personal injury, death, or Third Party property damage attributable to Seller's operation of the Seller Operated Assets prior to the Closing; (c) Taxes for which Seller is responsible pursuant to Section 7.8 or any Income Taxes of Seller (or any of its Affiliates) for any period (whether before, on or after the Effective Time); (d) off-site transportation and disposal by Seller of Hazardous Substances from or relating to the Seller Operated Assets in connection with Seller's operation of thereof; (e) the gross negligence or willful misconduct of Seller or the other Seller Indemnitees related to the operation by Seller of the Seller Operated Assets prior to the Execution Date; (f) the actions, suits or proceedings listed on Schedule 5.7; and (g) the Excluded Assets; provided, however, that such obligation and liability under clauses (a) and (b) above will only be a Retained Obligation insofar as Purchaser provides notice of the indemnifiable claim related to clause (a) or (b) on or before the second anniversary of the Closing Date.

"**Retained Records**" has the meaning set forth in Section 1.2(j).

"**Schedule Supplement**" has the meaning set forth in Section 5.1(f).

"**SEC Documents**" has the meaning set forth in Section 7.14(a).

"**Securities Act**" has the meaning set forth in Section 7.14(a).

"**Seller**" has the meaning set forth in the first paragraph of this Agreement.

"**Seller Indemnitees**" shall mean Seller, its Affiliates, and the officers, directors, managers, members, stockholders, general or limited partners, coventurers, employees, agents, representatives, advisors, subsidiaries, successors and assigns of Seller or its Affiliates.

"**Seller Indemnity Obligations**" has the meaning set forth in Section 11.2(c).

"**Seller Interim Matter**" shall mean any matter, solely to the extent related to the Assets operated by Purchaser, that (i) individually or in the aggregate would not give rise to Seller's right to terminate this Agreement pursuant to Section 10.1(d) and (ii) is discovered by Seller between the Execution Date and the Closing Date.

"**Seller Operated Assets**" shall mean Assets operated by Seller or its Affiliates as of the date of this Agreement.

"**Software**" means any and all (a) computer programs, including any and all software implementations of algorithms, models, and methodologies, whether in source code or object code, (b) databases and compilations, including any and all data and collections of data, whether machine readable or otherwise, (c) descriptions, flow-charts, and other work product used to design, plan, organize, and develop any of the foregoing, screens, user interfaces, report formats, firmware, development tools, templates, menus, buttons, and icons, and (d) all documentation, including user manuals and other training documentation, related to any of the foregoing.

"**Special Warranty**" has the meaning set forth in Section 7.9(a).

"**Subchapter K**" means Subchapter K of the Code.

"**Surface Contracts**" has the meaning set forth in Section 1.2(e).

"**Suspended Proceeds**" means proceeds of production which Seller is holding as of the Closing Date which are owing to Third Party owners of royalty, overriding royalty, working or other interests in respect of past production of oil, gas or other Hydrocarbons attributable to the Assets.

"**Target Closing Date**" has the meaning set forth in Section 9.1(a).

"**Target Formation**" shall mean (i) the entire correlative interval from 10,294 feet to 10,580 feet as shown on the log of the EOG Resources, Inc. – Milton Unit, Well No. 1 (API No. 42-255-31608), Section 64, John Random Survey, A-247, Karnes County, Texas, and (ii) the zone or formation containing the perforated interval(s) from which any Well located in the relevant Unit is currently producing oil and/or gas, as applicable, as reported for such Well to the applicable Governmental Body governing such Well as of the Effective Time.

"**Tax Audit**" has the meaning set forth in Section 7.8(e).

"**Tax Returns**" has the meaning set forth in Section 5.8.

"**Taxes**" means all federal, state, local, and foreign income, profits, franchise, sales, use, ad valorem, property, severance, production, excise, stamp, license, documentary, real property transfer or gain, gross receipts, goods and services, registration, capital, transfer, occupation, employment, payroll or withholding Taxes or other governmental fees or charges imposed by any taxing authority, including any interest, penalties or additional amounts which may be imposed with respect thereto.

"**Technology**" means, collectively, all documents, books, and records embodying the Intellectual Property and any other technical information used in the business of Seller, including copies of all manufacturing drawings, designs, formulae, algorithms, procedures, methods, techniques, ideas, know-how, research and development, technical data, programs, subroutines, tools, materials, specifications, bill of materials, processes, inventions (whether patentable or unpatentable and whether or not reduced to practice), apparatus, ideas, creations, improvements, customer lists, business plans, marketing studies, works of authorship, and other similar materials, and all recordings, graphs, drawings, reports, analyses, and other writings, and other tangible embodiments of the foregoing, in any form whether or not specifically listed herein, and all related technology, that are used in, incorporated in, embodied in, displayed by, or related to, or are used by Seller.

"**Third Party**" means any Person other than a Party or an Affiliate of a Party.

"**Third Party Claim**" has the meaning set forth in Section 11.3(b).

"**Title Arbitration Notice**" has the meaning set forth in Section 3.4(h).

"**Title Arbitrator**" has the meaning set forth in Section 3.4(h).

"**Title Benefit**" has the meaning set forth in Section 3.2(b).

"**Title Benefit Amount**" has the meaning set forth in Section 3.4(g).

"**Title Benefit Notice**" has the meaning set forth in Section 3.4(b).

"**Title Benefit Property**" has the meaning set forth in Section 3.4(b).

"**Title Claim Date**" has the meaning set forth in Section 3.4(a).

"**Title Defect**" has the meaning set forth in Section 3.2(c).

"**Title Defect Amount**" has the meaning set forth in Section 3.4(f).

"**Title Defect Deductible**" has the meaning set forth in Section 3.4(i).

"**Title Defect Notice**" has the meaning set forth in Section 3.4(a).

"**Title Defect Property**" has the meaning set forth in Section 3.4(a).

"**Trade Secrets**" means all trade secrets and confidential information, including all confidential drawings, designs, manufacturing processes, source code, know-how, technology, formulae, customer lists, inventions, and marketing information.

"**Transfer Taxes**" has the meaning set forth in Section 12.3.

"**Transition Services Agreement**" means the form Transition Services Agreement, to be dated as of Closing, attached as Exhibit E.

"**Units**" has the meaning set forth in Section 1.2(c).

"**Wells**" has the meaning set forth in Section 1.2(b).

IN WITNESS WHEREOF, this Agreement has been signed by each of the Parties on the date first above written.

SELLER

HUNT OIL COMPANY

By:/s/ Travis Armayor
Name: Travis V. Armayor
Title: Senior Vice President

PURCHASER

PENN VIRGINIA OIL & GAS, L.P.

By:/s/ Katherine Ryan
Name: Katherine J. Ryan
Title: Vice President, Chief Legal Counsel and Corporate Secretary

Exhibit A

Leases

The Parties agree that Exhibit A is intended to list all of the Leases which are intended to be included as part of the Assets to be conveyed to Purchaser hereunder. In the event that between the date of the execution of this Agreement and Closing it is determined that there are Leases that have been inadvertently omitted from or incorrectly described on Exhibit A, Seller, with the consent of Purchaser, which consent shall not be unreasonably withheld, conditioned or delayed, shall be permitted to supplement Exhibit A to include those Leases which have been inadvertently omitted or incorrectly described.

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 March 2, 2018, 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, 2017. 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).

/s/ GRANT THORNTON LLP

Houston, Texas
March 2, 2018

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Penn Virginia Corporation:

We consent to the incorporation by reference in the registration statements (Nos. 333-214709 and 333-216756) on Form S-3 and (No. 333-213979) on Form S-8 of Penn Virginia Corporation of our report dated March 15, 2016, with respect to the consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for the year ended December 31, 2015, which report appears in the December 31, 2017 annual report on Form 10-K of Penn Virginia Corporation.

Our report dated March 15, 2016 contains an explanatory paragraph that states that the Company has suffered recurring losses from operations and is dependent on obtaining additional financing to continue its planned principal business operations. These factors raise substantial doubt about its ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of that uncertainty.

/s/ KPMG LLP

Houston, Texas
March 2, 2018

Exhibit 23.3

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 2, 2018

Penn Virginia Corporation
14701 Saint Mary's Lane
Suite 275
Houston, Texas 77079

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our "Report as of December 31, 2017 on Reserves and Revenue of Certain Properties owned by Penn Virginia Corporation" (our Report) in Part I and in the "Notes to Consolidated Financial Statements" portions of the Annual Report on Form 10-K of Penn Virginia Corporation for the year ended December 31, 2017 (the Annual Report), to be filed with the United States Securities and Exchange Commission on or about March 2, 2018. In addition, we hereby consent to the incorporation by reference of our third-party letter report dated February 9, 2018, 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).

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

Exhibit 23.4

CONSENT OF WRIGHT & COMPANY, INC.

As independent petroleum consultants, Wright & Company, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-3 (File Nos. 333-214709 and 333-216756) and Form S-8 (File No. 333-213979) of Penn Virginia Corporation of information from our reserves report titled *Evaluation of Oil and Gas Reserves, To the Interests of Penn Virginia Corporation, In Certain Properties Located in Various States, Pursuant to the Requirements of the Securities and Exchange Commission, Effective January 1, 2015, Job 14.1649*, and dated January 9, 2015, and all references to our firm included in or made a part of the Penn Virginia Corporation Annual Report on Form 10-K to be filed with the Securities and Exchange Commission on or about March 1, 2018.

Wright & Company, Inc.
TX Firm Reg. No. F-12302

/s/ D. Randall Wright

By: D. Randall Wright
President

Brentwood, Tennessee
February 14, 2018

Exhibit 31.1

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

I, John A. Brooks, 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: March 2, 2018

/s/ JOHN A. BROOKS

John A. Brooks
Chief Executive Officer

Exhibit 31.2

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

I, Steven A. Hartman, Senior Vice President 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: March 2, 2018

/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, 2017, 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: March 2, 2018

/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, 2017, 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: March 2, 2018

/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

February 9, 2018

Penn Virginia Corporation
14701 Saint Mary's Lane
Suite 275
Houston, Texas 77079

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves, as of December 31, 2017, of certain properties in which Penn Virginia Corporation (Penn Virginia) has represented that it owns an interest. This evaluation was completed on February 9, 2018. Penn Virginia has represented that these properties account for 100 percent of Penn Virginia’s net proved reserves as of December 31, 2017. The properties evaluated herein are located in Oklahoma and Texas. 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, 2017. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Penn Virginia after deducting all interests owned by others.

Estimates of oil, condensate, NGL, and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue 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.

Data used in this evaluation were obtained from reviews with Penn Virginia personnel, from Penn Virginia files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Penn Virginia with respect to property interests, 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.

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 practices generally recognized by the petroleum industry, which are presented in the publication of the Society of Petroleum Engineers PRMS and publications of the Society of Petroleum Evaluation Engineers Monograph III and IV.

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 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 the appropriate reserves definitions.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Based on the current stage of field development, production performance, the development plans provided by Penn Virginia, and the 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 drill the locations as scheduled in its development plan.

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 usage, flare, and shrinkage resulting from field separation and processing. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit and at a pressure base of 14.65 pounds per square inch absolute. Gas reserves included herein are expressed in thousands of cubic feet (Mcf). Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to yields provided by Penn Virginia. 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.

<u>Definition of Reserves</u>

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.

The development status shown herein represents the status applicable on December 31, 2017. In the preparation of this study, data available from wells drilled on the evaluated properties through December 31, 2017, were used in estimating gross ultimate recovery. When applicable, gross production estimated through December 31, 2017, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves. In some fields this required that the production rates be estimated for up to 1 month, since production data from certain properties were available only through November 2017.

Primary Economic Assumptions

Revenue values in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth of future net revenue. Future gross revenue is 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 estimated production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from the future gross revenue. Present worth of future net revenue is calculated by discounting the future net revenue at the arbitrary rate of 10 percent per year 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.

Revenue values in this report were estimated for proved reserves using price and expenditure assumptions provided by Penn Virginia. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following assumptions were used for estimating future prices and expenditures:

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 arrangements. The oil, condensate, and NGL prices were calculated using differentials furnished by Penn Virginia to the reference price of $51.34 per barrel. The resulting volume-weighted average prices over the lives of the properties were $50.06 per barrel of oil and condensate and $18.02 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 arrangements. The gas prices were calculated for each property using differentials furnished by Penn Virginia to the reference price of $2.98 per million British thermal units ($/MMBtu) and held constant thereafter. British thermal unit factors provided by Penn Virginia were used to convert prices from $/MMBtu to dollars per thousand cubic feet ($/Mcf). The resulting volume-weighted average price over the lives of the properties was $2.891 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for each state in which the reserves are located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Penn Virginia based on historical 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 2017 values, provided by Penn Virginia, and were not adjusted for inflation. Abandonment costs, which are those costs associated with the removal of equipment, plugging of the wells, and reclamation and restoration associated with the abandonment, were provided by Penn Virginia for all properties.

Our estimates of Penn Virginia's net proved reserves attributable to the reviewed properties were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2017			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved				
Developed Producing	22,411	4,882	27,229	31,831
Developed Non-Producing	—	—	—	—
Total Proved Developed	22,411	4,882	27,229	31,831
Undeveloped	33,418	3,983	20,038	40,741
Total Proved	**55,829**	**8,865**	**47,267**	**72,572**

Note: Gas is 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 and costs attributable to the production and sale of Penn Virginia's net proved reserves of the properties evaluated, as of December 31, 2016, are summarized in thousands of dollars (M$) as follows:

	Developed Producing (M$)	**Developed Non-Producing (M$)**	**Total Proved Developed (M$)**	**Proved Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	1,290,032	—	**1,290,032**	1,801,334	**3,091,366**
Production and Ad Valorem Taxes	99,723	—	**99,723**	138,000	**237,723**
Operating Expenses	438,647	—	**438,647**	393,540	**832,187**
Capital and Abandonment Costs	21,174	—	**21,174**	668,824	**689,998**
Future Net Revenue	730,488	—	**730,488**	600,970	**1,331,458**
Present Worth at 10 Percent	442,214	—	**442,214**	166,756	**608,970**

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, 2017, estimated reserves.

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 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.

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 letter report has been prepared at the request of Penn Virginia. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

DeGOLYER and MacNAUGHTON

Texas Registered
Engineering Firm F-716

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

Exhibit 99.1

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 company did prepare the letter report addressed to Penn Virginia dated February 9, 2018, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

2. 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 International Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 33 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton