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, 2020

or

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

For the transition period from ____ to ____
Commission file number: 1-13283

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

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

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

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock, $0.01 Par Value	**PVAC**	**Nasdaq Global Select Market**

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

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

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

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

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

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

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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 $ 144,297,933 as of June 30, 2020 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the Nasdaq Global Select Market.

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

As of March 5, 2021, 15,266,598 shares of common stock of the registrant and 225,481.09 shares of Series A Preferred Stock of the registrant (which are redeemable for 22,548,109 shares of common stock) 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 3, 2021, 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, 2020

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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 the recently completed transactions with Juniper and its affiliates, including the risk that the benefits of the transactions may not be fully realized or may take longer to realize than expected, and that management attention will be diverted to transaction-related issues;
- risks related to completed acquisitions, including our ability to realize their expected benefits;
- the decline in, sustained market uncertainty of, and volatility of commodity prices for crude oil, natural gas liquids, or NGLs, and natural gas, including the recent dramatic decline of such prices;
- the impact of the COVID-19 pandemic, including reduced demand for oil and natural gas, economic slowdown, governmental actions, stay-at-home orders, interruptions to our operations or our customer′s operations;
- risks related to and the impact of actual or anticipated other world health events;
- risks related to acquisitions and dispositions, including our ability to realize their expected benefits;
- our ability to satisfy our short-term and long-term liquidity needs, including our ability to generate sufficient cash flows from operations or to obtain adequate financing, including access to the capital markets, to fund our capital expenditures and meet working capital needs;
- our ability to access capital, including through lending arrangements and the capital markets, as and when desired;
- 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;
- our ability to develop, explore for, acquire and replace oil and gas reserves and sustain production;
- changes to our drilling and development program;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- our ability to meet guidance, market expectations and internal projections, including type curves
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, NGLs and natural gas;
- our ability to contract for drilling rigs, frac crews, materials, supplies and services at reasonable costs;
- our ability to renew or replace expiring contracts on acceptable terms;
- our ability to obtain adequate pipeline transportation capacity or other transportation for our oil and gas production at reasonable cost and to sell our production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from that estimated in our proved oil and gas reserves;
- use of new techniques in our development, including choke management and longer laterals;
- drilling, completion and operating risks, including adverse impacts associated with well spacing and a high concentration of activity;
- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements with other parties and counterparty risk related to the ability of these parties to meet their future obligations;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- our reliance on a limited number of customers and a particular region for substantially all of our revenues and production;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties relating to general domestic and international economic and political conditions;
- the impact and costs associated with litigation or other legal matters;
- sustainability initiatives; 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, 2020.

The effects of the COVID-19 pandemic may give rise to risks that are currently unknown or amplify the risks associated with many of these factors.

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.

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.

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.

MEH. Magellan East Houston, a crude oil pricing index reference.

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.

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.

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.

RISK FACTOR SUMMARY

The following summarizes the principal factors that make an investment in Penn Virginia speculative or risky, all of which are more fully described in Part I, Item 1A. "Risk Factors" below. This summary should be read in connection with the Risk Factors section and should not be relied upon as an exhaustive summary of the material risks facing our business.

The following factors could materially adversely affect our business, results of operations, financial condition, cash flows, liquidity and the trading price of our common stock.

Risks Associated with our General Business

- The direct and indirect effects of the COVID-19 pandemic on our business, financial position, results of operations and/or cash flows, which will depend on future developments that are highly uncertain and cannot be predicted
- Prices for crude oil, NGLs and natural gas, which are dependent on many factors that are beyond our control
- Risks associated with drilling and operations activities, which are high-risk activities with many uncertainties and may not result in commercially productive reserves
- Risks associated with multi-well pad drilling and project development, which may result in volatility in our operating results
- Adverse impacts associated with a high concentration of activity and tighter drilling spacing
- Our ability to adhere to our proposed drilling schedule
- Our dependence on gathering, processing, refining and transportation facilities owned by others
- The unavailability, high cost or shortage of drilling rigs, frac crews, equipment, raw materials, supplies, oilfield services or personnel, which may restrict our operations
- Our ability to find or acquire additional oil and gas reserves that are economically recoverable
- Our ability to attract and retain key members of management, qualified Board members and other key personnel
- Our ability to establish production on the acreage of certain of our undeveloped leasehold assets that are subject to leases that will expire over the next several years unless production is developed
- Actions we or other operators may take when drilling, completing, or operating wells that they own that may adversely affect certain of our wells
- Our exposure to the credit risk of our customers
- Our participation in oil and gas leases with third parties, who may not be able to fulfill their commitments to our projects
- The accuracy of our estimates of oil and gas reserves and future net cash flows, which are not precise, and undeveloped reserves, which may not ultimately be converted into proved producing reserves
- The incurrence of impairments on our oil and gas properties
- Our ability to obtain sufficient capital
- Risks associated with property acquisitions
- Losses resulting from title deficiencies
- Difficulties associated with being a small company competing in a larger market
- Our lack of diversification and risks associated with operating primarily in one major contiguous area
- Operating risks, including risks associated with hydraulic fracturing

Financial and Related Risks

- Our substantial indebtedness
- A reduction in our borrowing base
- Restrictive covenants under the Credit Facility and the Second Lien Facility, which could limit our financial flexibility
- Derivative transactions, which may limit our potential gains and involve other risks
- Investor sentiment towards the oil and gas industry, which could adversely affect our ability to raise equity and debt capital

Legal and Regulatory Risks

- Various laws and regulations that could adversely affect the cost, manner or feasibility of doing business, including climate change legislation, laws and regulations restricting emissions of greenhouse gases or prohibiting, restricting, or delaying oil and gas development on public lands, and federal state and local legislation and regulatory initiatives relating to hydraulic fracturing
- Our ability to access water to drill and conduct hydraulic fracturing and difficulties associated with disposing of produced water gathered from drilling and production activities
- Risks associated with legal proceedings

Tax-Related Risks

- Our ability to use net operating loss carryforwards to offset future taxable income, which may be subject to certain limitations
- The continued availability of certain federal income tax deductions with respect to oil and gas exploration and development

Technology-Related Risks

- Our ability to keep pace with technological developments in our industry
- Risks relating to cybersecurity incidents

Risks Related to Ownership of Our Common Stock

- Risks associated with Juniper's control of the Company, including potential conflicts between Juniper's interests and the interests of the Company and its stockholders
- Certain provisions of our certificate of incorporation and our bylaws that 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
- The volatility of the market price of our common stock
- The actions of so-called "activist" shareholders, which could impact the trading value of our securities
- Future sales or other dilution of our equity, which may adversely affect the market price of our common stock

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

General

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 of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale, or the Eagle Ford, in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

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

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

Juniper Transactions

At a special meeting held on January 13, 2021, the Company’s shareholders approved the potential issuance of up to 22,597,757 shares of our common stock, par value $0.01 per share, or the Common Stock, upon the redemption or exchange of up to 225,977.57 shares of Series A Preferred Stock, par value $0.01 per share, of the Company, or the Series A Preferred Stock, together with up to 22,597,757 common units representing limited partner interests (the “Common Units”) of PV Energy Holdings, L.P. (the “Partnership”). On January 14, 2021, the Company amended its articles of incorporation (the “Articles of Amendment”) creating a series of the Company’s preferred stock consisting of 300,000 shares and designated as the Series A Preferred Stock, as well as establishing the powers, preferences and rights of the preferred stock series and the qualifications, limitations and restrictions thereof.

On January 15, 2021, or the Closing Date, the Company consummated the previously announced transactions,(collectively, the “Juniper Transactions”), contemplated by: (i) the Contribution Agreement, dated November 2, 2020 (the “Contribution Agreement”), by and among the Company, the Partnership, and JSTX Holdings, LLC, or JSTX, an affiliate of Juniper Capital Advisors, L.P. (“Juniper Capital”), and, together with its affiliates (“Juniper”); and (ii) the Contribution Agreement, dated November 2, 2020 (the “Asset Agreement”, and, together with the Contribution Agreement, the Juniper Transaction Agreements), by and among Rocky Creek Resources, LLC, an affiliate of Juniper Capital (“Rocky Creek”), the Company and the Partnership.

In connection with the consummation of the Juniper Transactions, the Company completed a reorganization into an up-C structure, or the Reorganization (which is intended to, among other things, result in the holders of the Series A Preferred Stock, having a voting interest in the Company that is commensurate with such holders’ economic interest in the Partnership), including (i) the conversion of each of the Company’s corporate subsidiaries into limited liability companies which are disregarded for U.S. federal income tax purposes, including the conversion of Penn Virginia Holding Corp. into Penn Virginia Holdings, LLC, a Delaware limited liability company, or Holdings, and (ii) the Company’s contribution of all of its equity interests in Holdings to the Partnership in exchange for 15,268,686 newly issued Common Units.

On the Closing Date, (i) pursuant to the terms of the Contribution Agreement, JSTX contributed to the Partnership, as a capital contribution, $150 million in cash in exchange for 17,142,857 newly issued Common Units and the Company issued to JSTX 171,428.57 shares of Series A Preferred Stock at a price equal to the par value of the shares acquired, and (ii) pursuant to the terms of the Asset Agreement, Rocky Creek contributed to our operating subsidiary certain oil and gas assets in exchange for 5,405,252 newly issued Common Units and the Company issued to Rocky Creek 54,052.52 shares of Series A Preferred Stock at a price equal to the par value of the shares acquired, including 495,900 Common Units and 4,959 shares of Series A Preferred Stock placed in an indemnity escrow to support post-closing indemnification claims, 50% of such escrowed amount to be disbursed on July 14, 2021 and the remainder on January 15, 2022.

On the Closing Date, in connection with and upon the consummation of the Juniper Transactions, the general partner of the Partnership, entered into that certain Amended and Restated Agreement of Limited Partnership of the Partnership, dated January 15, 2021, or the A&R Partnership Agreement, with the Company, JSTX, and Rocky Creek, as limited partners, to provide for or reflect, among other things:

- the admission of JSTX and Rocky Creek as limited partners;
- the recapitalization of the Partnership into the Common Units; and
- the redemption right of each limited partner (other than the Company), which entitles such limited partner to cause the Partnership to redeem, from time to time on or after the date that is 180 days after the Closing Date, all or a portion of its Common Units (together with one one-hundredth (1/100th) of a share of Series A Preferred Stock for each Common Unit to be redeemed), in exchange for, at the Partnership's option, shares of Common Stock, on a one-for-one basis or a cash payment equal to the average of the volume-weighted closing price of one share of Common Stock for the five trading days prior to the date the limited partner delivers a notice of redemption for each the Common Unit redeemed (subject to customary adjustments, including for stock splits, stock dividends and reclassifications).

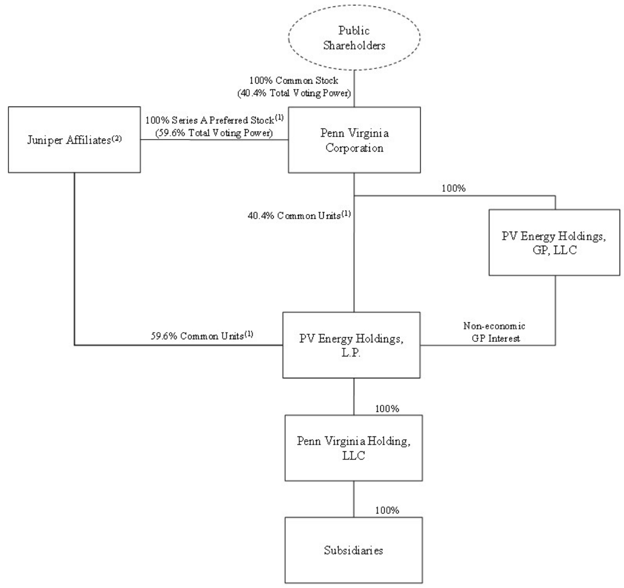
On the Closing Date, in connection with the consummation of the Juniper Transactions, the Company, JSTX and Rocky Creek entered into that certain Investor and Registration Rights Agreement, dated January 15, 2021, or the Investor Agreement, providing for, together with the Articles of Amendment, certain rights and obligations with respect to the governance of the Company, including rights to nominate a number of members of the Company's board of directors, or the Board, based on Juniper's beneficial ownership of the Company, and certain registration rights with respect to the Common Stock issuable upon redemption of the Common Units and Series A Preferred Stock pursuant to the A&R Partnership Agreement.

On the Closing Date, in accordance with the Articles of Amendment and the Investor Agreement, the Board was increased from four members to nine members, and Juniper designated five new members to the Board (the directors from time to time appointed to the Board pursuant to Juniper's rights under the Investor Agreement and Articles of Amendment, the "Investor Directors").

Juniper and its permitted transferees shall continue to have the right to appoint Investor Directors to the Board and to have Investor Directors sit on certain committees of the Board for so long as Juniper continuously owns Common Stock (or Common Units and shares of Series A Preferred Stock redeemable or exchangeable therefor), subject to applicable law, stock exchange rules and step-downs in the number of directors Juniper may designate based on Juniper's beneficial ownership of the Company's voting power. Pursuant to the Investor Agreement, Juniper has also agreed to vote in favor of the nominees proposed by the Nominating & Governance Committee of the Board at the Company's 2021 Annual Meeting of Shareholders.

Concurrent with the closing of the Juniper Transactions, on the Closing Date, the following transactions occurred: (i) the Agreement and Amendment No. 9 to Credit Agreement, or the Ninth Amendment, to the credit agreement, or Credit Facility, became effective and a prepayment of $80.5 million of outstanding borrowings under the Credit Facility was made plus accrued interest of $0.1 million, (ii) the amendment dated November 2, 2020 (the "Second Lien Amendment") to the Second Lien Credit Agreement dated as of September 29, 2017, or the Second Lien Facility, became effective and a prepayment of $50.0 million of outstanding advances under the Second Lien Facility was made plus accrued interest of $0.2 million in accordance with the Second Lien Amendment, (iii) total payments of $17.8 million in cash were completed for transaction and debt issue costs, including (A) $16.0 million associated with the Juniper Transactions, (B) $1.4 million associated with the Second Lien Amendment and (C) $0.4 million associated with the Ninth Amendment and (iv) a combined payment of $1.3 million including principal and accrued interest was made to liquidate the outstanding advances attributable to a single participant lender.

On March 5, 2021, the Company had outstanding 15,266,598 shares of Common Stock and 225,481.09 shares of Series A Preferred Stock. Holders of the Company's Common Stock owned approximately 40 percent of the total voting power and economic interest in the Company, and Juniper, through JSTX and Rocky Creek, owned approximately 60 percent of the total voting power and economic interest in the Company through the Series A Preferred Stock and Common Units.



(1) The Common Units are economic interests of the Partnership and the Series A Preferred Stock are non-economic voting interests in the Company.
(2) Represented by JSTX and Rock Creek.

Each 1/100th of a share of Series A Preferred Stock has no economic rights but entitles its holder to one vote on all matters to be voted on by shareholders generally. Holders of Common Stock and Series A Preferred Stock vote together as a single class on all matters presented to our shareholders for their vote or approval, except as otherwise required by applicable law or by our Articles of Incorporation, as amended. As discussed above, under the A&R Partnership Agreement, each holder of Common Units has the right to cause the Company to redeem on or after the date that is 180 days after the Closing Date, all or a portion of its Common Units (together with one one-hundredth (1/100th) of a share of Series A Preferred Stock for each Common Unit to be redeemed), in exchange for, at the Partnership's option, shares of Common Stock, on a one-for-one basis, or cash. However, because Penn Virginia is a holding company with no independent means of generating revenues and the assets of the consolidated Company all reside in operating subsidiaries, the holders of Common Units would be entitled to participate in any cash distribution from the Company's operating subsidiaries whether or not they convert their Common Units into Common Stock.

For additional information regarding the Juniper Transactions, the Ninth Amendment, the Second Lien Amendment and the transaction costs associated therewith, see *Management's Discussion and Analysis of Financial Condition and Results of Operations* included in Part II, Item 7 that follows and Notes 2 and 9 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." Additionally, for a discussion of certain risks relating to our organizational structure following the Juniper Transactions, see *Risk Factors - Penn Virginia is a holding company. Penn Virginia's only material asset is its equity interest in the Partnership, and Penn Virginia is accordingly dependent upon distributions from the Partnership to pay taxes and cover its operating expenses and other obligations.* in Part I, Item 1A that follows.

Current Operations

Including the properties contributed by Rocky Creek in connection with the Asset Agreement, we lease a highly contiguous position of approximately 102,100 gross (90,100 net) acres as of March 5, 2021 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 2020, our total sales volume was comprised of 77 percent crude oil, 13 percent NGLs and 10 percent natural gas. Crude oil accounted for 93 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, 2020, our total proved reserves were approximately 126 MMBOE, of which 40 percent were proved developed reserves and 78 percent were crude oil. As of December 31, 2020, we had 532 gross (451.3 net) productive wells, approximately 98 percent of which we operate, and leased approximately 98,300 gross (86,300 net) acres of leasehold and royalty interests, approximately 7 percent of which were undeveloped. Approximately 93 percent of our total acreage was HBP and included a substantial number of undrilled locations. During 2020, we drilled, completed and turned to sales 23 gross (20.6 net) wells. For additional information regarding our production, reserves, drilling activities, wells and acreage, see Part I, Item 2, "Properties."

In 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 Gonzales and Lavaca Counties, Texas, or the Hunt Acquisition. For additional information regarding this transaction, see Note 4 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Key Contractual Arrangements

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

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, 2020, there were no drilling, completion or materials agreements with terms that extended beyond one year.

Crude oil gathering and transportation service contracts. We have long-term agreements that provide us with field gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production through February 2041 and February 2026, respectively, as well as volume capacity support for certain downstream interstate pipeline transportation.

Crude oil storage. Through April 2021, we have access of up to a maximum of 520,000 barrels of tank capacity at a number of locations in the South Texas region with three vendors including up to approximately 250,000 barrels (180,000 barrels as a component of the crude oil gathering agreement referenced above) at the service provider's central delivery point facility, or CDP, in Lavaca County, Texas, up to 90,000 barrels with a downstream interstate pipeline at their facility in DeWitt County, Texas and up to 62,000 barrels with a marketing affiliate of the aforementioned downstream interstate pipeline within their system on a firm basis and an additional 120,000 barrels, if available, on a flexible basis through April 2021. For additional information relating to crude oil storage see Note 14 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

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

Natural gas processing contracts. We have two agreements that provide us with services to process our wet gas production into NGL products and dry, or residue, gas. The more significant of these agreements extends through June 2029 while the other agreement, which represents a minor portion of our total processing requirements, is evergreen in term with either party having the right to terminate with 30-days' notice to the counterparty.

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, 2020, approximately 56 percent of our consolidated product revenues were attributable to three customers, each of whom accounted for at least 10 percent: Phillips 66 Company; BP Products North America Inc. and Shell Trading (US) Company. There were no other customers that individually accounted for more than 10 percent of our consolidated product revenues.

Seasonality

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

Competition

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

Government Regulation and Environmental Matters

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

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

Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities for failure to comply. Violations and liabilities with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and cash flows. In certain instances, citizens or citizen groups also have the ability to bring legal proceedings against us if we are not in compliance with environmental laws or to challenge our ability to receive environmental permits that we need to operate. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2020, we have recorded asset retirement obligations of $5.5 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, 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 or the ability to conduct oil and gas development 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. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

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

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into regulated waters, such as waters of the United States. The discharge of pollutants, including dredge or fill materials in regulated wetlands, into regulated waters or wetlands without a permit issued by the EPA, the U.S. Army Corps of Engineers, or the Corps, or the state is prohibited. The Clean Water Act has been interpreted by these agencies to apply broadly. The EPA and the Corps released a rule to revise the definition of “waters of the United States,” or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. However, the EPA rescinded this rule in 2019 and promulgated the Navigable Waters Protection Rule in 2020. The Navigable Waters Protection Rule defined what waters qualify as navigable waters of the United States and are under Clean Water Act jurisdiction. This new rule has generally been viewed as narrowing the scope of waters of the United States as compared to the 2015 rule, but litigation in multiple federal district courts is currently challenging the rescission of the 2015 rule and the promulgation of the Navigable Waters Protection 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. In addition, in some instances, the operation of underground injection wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells, and regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission, or TRC, adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water or other oil and gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be, or determined to be, contributing to seismic activity, then TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that disposal well. TRC has used this authority to deny permits for waste disposal wells. The potential adoption of federal, state and local legislation and regulations intended to address induced seismic activity in the areas in which we operate could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays.

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

Chemical Disclosures Related to Hydraulic Fracturing. Texas has implemented chemical disclosure requirements for hydraulic fracturing operations. We currently disclose 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, for example, the EPA issued final rules to subject oil and gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells, compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. Further, in May 2016, the EPA issued final NSPS governing methane emissions from the oil and gas industry as well as source determination standards for determining when oil and gas sources should be aggregated for CAA permitting and compliance purposes. However, in August 2020 the EPA rescinded methane and volatile organic compound emissions standards for new and modified oil and gas transmission and storage infrastructure, as well as methane limits for new and modified oil and gas production and processing equipment. The EPA also relaxed requirements for oil and gas operators to monitor emissions leaks. In President Biden's Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden directed the EPA to consider suspending, rescinding, or revising the Trump Administration's NSPS rule for the oil and gas sector. The U.S. Bureau of Land Management, or BLM, finalized its own 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 subsequently announced a revised rule which would scale back the waste-prevention requirements of the 2016 rule, but this revised rule was vacated by a California federal district court in 2020, a decision which BLM has appealed to the Ninth Circuit Court of Appeals. However, separately, the federal district court of Wyoming vacated the original 2016 rule in October 2020. These rules have required changes to our operations, including the installation of new equipment to control emissions. The EPA had announced in 2016 an intent to impose methane emission standards for existing sources, but the agency was sued by multiple states for failing to implement these standards following the agency's withdrawal of information collection requests for oil and gas facilities. These rules would result in an increase to our operating costs and change to our operations. As a result of this continued regulatory focus, future federal and state regulations of the oil and gas industry remain a possibility and could result in increased compliance costs on our operations.

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

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

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

Greenhouse Gas Emissions. In response to findings that emissions of carbon dioxide, methane and other 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. In 2020, the Trump administration withdrew the United States from the Paris Agreement, but under the direction of President Biden, the United States rejoined the Paris Agreement in February 2021. President Biden is likely to update the U.S.’s nationally determined contributions and take executive action or support legislation in furtherance of achieving the U.S.’s GHG emissions goals.

In August 2015, the EPA issued new regulations limiting carbon dioxide emissions from existing power generation facilities. Under this rule, nationwide carbon dioxide emissions would be reduced by approximately 30 percent from 2005 levels by 2030 with a flexible interim goal. Several industry groups and states challenged the rule. On February 9, 2016, the U.S. Supreme Court stayed the implementation of this rule pending judicial review. In August 2019, the EPA finalized the repeal of the 2015 regulations and replaced them with the Affordable Clean Energy rule, or ACE, that designates heat rate improvement, or efficiency improvement, as the best system of emissions reduction for carbon dioxide from existing coal-fired electric utility generating units. However, in January 2020, the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE rule and ruled that the repeal of the Obama-era regulations should also be vacated; the court is delaying issuing the latter vacatur mandate until such time that the EPA responds to the court’s decision through a new rulemaking action. Thus, the Biden Administration’s EPA is likely to promulgate a new replacement for the 2015 regulations.

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

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

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

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

President Biden and the Democratic Party, which currently controls Congress, have identified climate change as a priority, and it is likely that new executive orders, regulatory action, and/or legislation targeting greenhouse gas emissions, or prohibiting, delaying or restricting oil and gas development activities in certain areas, will be proposed and/or promulgated during the Biden Administration. For example, the acting Secretary of the Department of the Interior recently issued an order preventing staff from producing any new fossil fuel leases or permits without sign-off from a top political appointee, and President Biden recently announced a moratorium on new oil and gas leasing on federal lands and offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. President Biden's order also established climate change as a primary foreign policy and national security consideration, affirms that achieving net-zero greenhouse gas emissions by or before midcentury is a critical priority, affirms President Biden's desire to establish the United States as a leader in addressing climate change, generally further integrates climate change and environmental justice considerations into government agencies' decision making, and eliminates fossil fuel subsidies, among other measures.

Finally, 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. Similar protections are given to bald and golden eagles under the Bald and Golden Eagle Protection Act and to migratory birds under the Migratory Bird Treaty Act, and similar protections may be available to certain species protected under state laws.

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

Employees

We had a total of 87 employees as of December 31, 2020, all of whom were full-time employees. The total as of December 31, 2020 represented a decline from 94 employees as of December 31, 2019 due primarily to a limited reduction-in-force, or RIF, during the third quarter of 2020.

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, Audit Committee Charter, Compensation and Benefits Committee Charter, Nominating and Governance Committee Charter and Reserves 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.

Risks Associated with our General Business

The COVID-19 pandemic has adversely affected our business, and the ultimate effect on our business, financial position, results of operations and/or cash flows will depend on future developments, which are highly uncertain and cannot be predicted.

The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains, and created significant volatility and disruption of financial and commodity markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. As a result, there has been a significant reduction in demand for and prices of oil, NGLs and natural gas, which has adversely impacted, and is expected to continue to adversely impact, our business, financial position, results of operations and cash flows. The extent of the impact of the COVID-19 pandemic on our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including how the pandemic and measures taken in response to the pandemic impact demand for oil, NGLs and natural gas, the availability of personnel, equipment and services critical to our ability to operate our properties and the impact of potential governmental restrictions on travel, transports and operations.

There is uncertainty around the extent and duration of the disruption. The degree to which the COVID-19 pandemic continues to adversely impacts our results will depend on future developments, which are highly uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, including the impact of coronavirus mutations and resurgences, its severity, the actions to contain the virus or treat its impact, the development, availability and public acceptance of effective treatments or vaccines, its impact on the U.S. and world economies, the U.S. capital markets and market conditions, the availability of federal, state, or local funding programs, and how quickly and to what extent normal economic and operating conditions can resume.

Prices for crude oil, NGLs and natural gas are dependent on many factors that are beyond our control and strongly affect our financial condition, results of operations and cash flows.

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

- domestic and foreign supplies of crude oil, NGLs and natural gas;
- domestic and foreign consumer demand for crude oil, NGLs and natural gas;
- political and economic conditions in oil or gas producing regions;
- the extent to which the members of the Organization of Petroleum Exporting Countries and other oil exporting nations (“OPEC+”) agree upon and maintain production constraints and oil price controls;
- overall domestic and foreign economic conditions, including adverse conditions driven by political, health or weather events;
- prices and availability of, and demand for, alternative fuels;
- the effect of energy conservation efforts, alternative fuel requirements and climate change-related initiatives;
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil, natural gas and NGLs so as to minimize emissions of carbon dioxide and methane GHGs;
- volatility and trading patterns in the commodity-futures markets;
- technological advances or social attitudes and policies affecting energy consumption and energy supply;
- political and economic events that directly or indirectly impact the relative strength or weakness of the United States dollar, on which crude oil prices are benchmarked globally, against foreign currencies;
- changes in trade relations and policies, including the imposition of tariffs by the United States or China;
- risks related to the concentration of our operations in the Eagle Ford Shale field in South Texas;
- speculation by investors in oil and gas;
- the availability, cost, proximity and capacity of gathering, processing, refining and transportation facilities;
- the cost and availability of products and personnel needed for us to produce oil and gas;
- weather conditions;
- the impact and uncertainty of world health events, including the COVID-19 pandemic; and
- domestic and foreign governmental relations, regulation and taxation, including limits on the United States’ ability to export crude oil.

For example, oil and natural gas prices continued to be volatile in 2020, as the slowdown in global economic activity attributable to COVID-19 resulted in a dramatic decline in the demand for energy, including significantly reduced demand for our products. The NYMEX oil prices in 2020 ranged from a high of $63.27 to a low of $(37.63) per Bbl while the spot market prices for natural gas prices in 2020 ranged from a high of $3.08 to a low of $1.34 per MMBtu. Further, these prices ranged from highs to lows of $66.40 to $47.47 per Bbl and $23.86 to $2.45 per MMBtu, respectively, during the period from January 1, 2021 to March 5, 2021. Though declining U.S. production has helped mitigate the supply and demand imbalance experienced during 2020, we expect that oil prices in the near term will continue to be influenced by the duration and severity of the COVID-19 pandemic and its resulting impact on oil and natural gas demand, the extent to which countries abide by the OPEC+ production agreement and U.S. production levels.

The long-term effects of these and other conditions on the prices of oil and natural gas are uncertain, and there can be no assurance that the demand or pricing for our products will follow historic patterns or recover meaningfully in the near term. Any substantial or extended decline, or sustained market uncertainty, in the actual prices of crude oil, NGLs or natural gas would have a material adverse effect on our business, financial position, results of operations, cash flows and borrowing capacity, stock price, 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.

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.

Drilling and operations activities are high-risk activities with many uncertainties and may not result in commercially productive reserves.

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

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

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

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

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

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

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

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

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

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

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

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

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

Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing.

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the risk of unintentional communication with other adjacent wells and the potential to reduce total recoverable reserves from the reservoir. If these risks materialize and negatively impact our results of operations relative to guidance or market expectations, the research analysts who cover us may downgrade our common stock or change their recommendations or earnings or performance estimates, which may result in a decline in the market price of our common stock.

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.

For example, we temporarily suspended our drilling program from April 2020 through September 2020 to mitigate the impact of the adverse economic conditions attributable to COVID-19 as well as the impact of the precipitous decline in crude oil prices.

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

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

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

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

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

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

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

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

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

The ability to attract and retain key members of management, qualified Board members and other key personnel is critical to the success of our business and may be challenging.

Our success will depend to a large extent upon the efforts and abilities of our management team and having experienced individuals serving on our Board who are also knowledgeable about our operations and our industry. We experienced significant turnover on our executive team and Board in 2019 through first quarter 2021. If we experience similar turnover in the future, we may be unable to timely replace the talents and skills of our management team or directors if one or more did not continue serving. The success of our business also depends on other 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. We do not maintain key-man life insurance with respect to any of our employees. Acquiring and keeping personnel could prove more difficult or cost substantially more than estimated. These factors could cause us to incur greater costs or prevent us from pursuing our development and exploitation strategy as quickly as we would otherwise wish to do. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them adequately or in a timely manner and we could experience significant declines in productivity.

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

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

Certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that they own.

The drilling and production of potential locations by us or other operators could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells by us or other operators could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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 2020, approximately 56 percent of our total consolidated product revenues resulted from three of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

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

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

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

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

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

At December 31, 2020 and December 31, 2019, approximately 60 percent and 58 percent, respectively, of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped 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, 2020, includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $898 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, 2020, we wrote-off 34.0 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 based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general. 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 $449 million and $454 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 after tax discounted future net revenues from proved properties adjusted for costs excluded from amortization, or a Ceiling Test. The estimated after tax 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 fiscal 2020, we recorded impairments of our oil and gas properties of $392 million. Because the Ceiling Test utilizes commodity prices based on a trailing twelve month average, as of December 31, 2020, it does not fully reflect the substantial decline in commodity prices that accelerated early in the second quarter of 2020 due to the COVID-19 pandemic and the ongoing disruption in global energy markets. Accordingly, we may incur an additional impairment during the first quarter of 2021.

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

The oil and gas industry is capital intensive. We incur and expect to continue to incur substantial capital expenditures for the acquisition, exploration and development of oil and gas reserves. We incurred approximately $135.3 million in acquisition, exploration and development costs during the year ended December 31, 2020. We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and, if necessary, through borrowings under our credit agreement (as defined below). However, our cash flow from operations and access to capital are subject to a number of variables, including: (i) the volume of oil and gas we are able to produce from existing wells, (ii) our ability to transport our oil and gas to market, (iii) the prices at which our commodities are sold, (iv) the costs of producing oil and gas, (v) global credit and securities markets, (vi) the ability and willingness of lenders and investors to provide capital and the cost of the capital, (vii) our ability to acquire, locate and produce new reserves, (viii) the impact of potential changes in our credit ratings and (ix) our proved reserves. Additionally, a negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

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

Our property acquisitions carry significant risks.

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

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

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

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

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

We may incur losses as a result of title deficiencies.

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

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

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel, and we may face difficulties in competing with larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and gas plays, to acquire new acreage, and to develop attractive oil and gas projects, are significant. We face intense competition in all areas of our business from companies with greater and more productive assets, greater access to capital, substantially larger staffs and greater financial and operating resources than we have. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our limited size has placed us at a disadvantage with respect to funding our capital and operating costs, and means that we are more vulnerable to commodity price volatility and overall industry cycles (such as the volatility and general economic challenges attributable to COVID-19), are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development or production play can have a disproportionately negative impact on us. We also compete for people, including experienced geologists, geophysicists, engineers and other professionals. Our limited size has placed us at a disadvantage with respect to attracting and retaining management and other professionals with the technical abilities necessary to successfully operate our business.

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

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

Financial and Related Risks

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 $377.6 million of outstanding debt at March 5, 2021, including $228.9 million under the Credit Facility, and $148.7 million, excluding unamortized discount and issuance costs, under the Second Lien Facility.

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

Additionally, we may incur substantially more debt in the future. Our Credit Facility and the Second Lien Facility contain restrictions that limit our ability to incur indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. If we were to incur additional indebtedness without retiring existing debt, the risks described above could be magnified.

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 $375 million as of December 31, 2020 with borrowings limited to a maximum of $350 million. As of March 5, 2021, we had $228.9 million outstanding under the Credit Facility. Our borrowing base is generally redetermined at least twice each year and is scheduled to next be redetermined in October 2021 assuming we continue to meet certain conditions under the Credit Facility thereby foregoing a Spring 2021 redetermination. During a borrowing base redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Facility. In the event of a decline in crude oil, NGL or natural gas prices or for other reasons deemed relevant by our lenders, the borrowing base under the Credit Facility may be reduced. Additionally, the lenders typically may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. 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. Furthermore, a determination to lower the borrowing base in the future to a level less than our outstanding indebtedness thereunder would require us to repay any indebtedness in excess of the redetermined borrowing base. Any such repayment or reduced access to funds 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.

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

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

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

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

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

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC, to promulgate rules and regulations implementing the Dodd-Frank Act. While some of these rules have been finalized, some have not been finalized or implemented, and it is not possible at this time to predict when this will be accomplished. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; however, this initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. The CFTC has subsequently issued proposals for new rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions for bona fide hedging transactions, though these rules have not been finalized and the impact of those provisions on us is uncertain at this time.

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

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

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

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

A negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in our industry. The negative sentiment toward our sector versus other industry sectors has led to lower oil and gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Such development could result in a reduction of available capital funding for potential development projects or diminution of capital to fund our business which could impact our future financial results.

Legal and Regulatory Risks

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. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Moreover, these risks are likely to be enhanced with President Biden taking office and Democrats gaining control of Congress. For example, see Part I, Item 1, “Business - *Government Regulation and Environmental Matters - Greenhouse Gas Emissions*” for information about certain actions the Biden Administration has taken targeting greenhouse gas emissions. 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*.”

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

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

In addition, we must dispose of the fluids produced from oil and natural gas production operations, including produced water. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from recent seismic events near underground disposal wells that are used for the disposal by injection of produced water resulting from oil and natural gas activities. In March 2016, the United States Geological Survey identified Texas and Colorado as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, in Texas, the RRC adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal.

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

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

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In the future, the United States may also choose to adhere to international agreements targeting GHG reductions. The adoption of legislation or regulatory programs or other government action to reduce emissions of GHGs or restrict, delay or prohibit oil and gas development on public lands could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements, or prevent us from conducting operations in certain areas. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. These risks are likely to be enhanced with President Biden taking office and Democrats gaining control of Congress. See Part I, Item 1, "Business - *Government Regulation and Environmental Matters -Greenhouse Gas Emissions*." Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, results of operations and cash flows. Reduced demand for the oil and gas that we produce could also have the effect of lowering the value of our reserves.

In addition, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If such climactic events were to occur more frequently or with greater intensity, our exploration and development activities and ability to transport our production to market could be adversely affected, as these events could cause a loss of production from temporary cessation of activity or damaged facilities and equipment. 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 - *Government Regulation and Environmental Matters*."

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

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

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

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

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 Bald and Golden Eagle Protection 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.

We may be involved in legal proceedings that could result in substantial liabilities.

Like many oil and gas companies, from time to time, we expect to be involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of business. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

Tax-Related Risks

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 10 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, 2020, we do not believe that an ownership change has occurred; however, to the extent an ownership change has occurred or were to occur in the future, it is possible that the limitations imposed on our ability to use pre-ownership change losses could cause a significant net increase in our U.S. federal income tax liability and could cause U.S. federal income taxes to be paid earlier than they otherwise would be paid if such limitations were not in effect. In addition, U.S. NOLs generated on or after January 1, 2018, can be limited to 80 percent of taxable income. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

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

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

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

Technology-Related Risks

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

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

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

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

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

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

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

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

Risks Related to the Ownership of Our Common Stock

Juniper controls the Company, and their interests may conflict with the Company's and its shareholders' interests in the future.

Juniper beneficially owns approximately 60% of our voting securities. As a result, Juniper is able to control the election and removal of our directors and thereby control our policies and operations and its interests may not in all cases be aligned with other shareholders' interests. In addition, Juniper may have an interest in pursuing acquisitions, divestitures and other transactions that, in its judgment, could enhance its investment, even though such transactions might involve risks to other shareholders. For example, Juniper could cause us to make acquisitions that increase our indebtedness or cause us to sell revenue-generating assets. Additionally, Juniper and its designated directors are not obligated to present any business opportunities (other than those presented to such directors in their roles as directors of the Company) to us.

In addition, Juniper is able to determine the outcome of all matters requiring shareholder approval and is able to cause or prevent a change of control of the Company or a change in the composition of our Board of Directors and could preclude any acquisition of the Company. This concentration of voting control could deprive shareholders of an opportunity to receive a premium for their shares of Common Stock as part of a sale of the Company and ultimately might affect the market price of our Common Stock.

Moreover, Juniper has certain director designation rights entitling them to designate up to five members of the Board out of a total of nine directors, with such designation rights being subject to certain step-downs.

We are a "controlled company" within the meaning of the Nasdaq rules and, as a result, expect to qualify for exemptions from certain corporate governance requirements.

Juniper controls a majority of the voting power of our capital stock. As a result, we are a "controlled company" within the meaning of the corporate governance standards of Nasdaq. As a result, we are not required to comply with certain corporate governance requirements, including the requirement to have a majority of the board of directors be independent directors and the requirement to have compensation and nominating committees that are composed entirely of independent directors. While we have not elected to utilize these exemptions, in the future we could elect to do so. If we were to utilize any such exemptions, our shareholders would not have the same protections afforded to shareholders of companies that are subject to all of the corporate governance rules for Nasdaq-listed companies.

Penn Virginia is a holding company. Penn Virginia's only material asset is its equity interest in the Partnership, and Penn Virginia is accordingly dependent upon distributions from the Partnership to pay taxes and cover its operating expenses and other obligations.

Following the Juniper Transactions, Penn Virginia is a holding company and has no material assets other than its equity interest in the Partnership. Penn Virginia has no independent means of generating revenue. To the extent the Partnership has available cash, Penn Virginia intends to cause the Partnership to make (i) pro rata distributions to its limited partners, including Penn Virginia, in an amount sufficient to allow Penn Virginia to pay its taxes and (ii) payments to Penn Virginia to cover its operating expenses and other obligations. To the extent that Penn Virginia needs funds and the Partnership or its subsidiaries are restricted from making such distributions or payments under applicable law or regulation or under the terms of any future financing arrangements, or are otherwise unable to provide such funds, Penn Virginia's liquidity and financial condition could be materially adversely affected.

Moreover, because Penn Virginia has no independent means of generating revenue, Penn Virginia's ability to pay dividends will be dependent on the ability of the Partnership to make cash distributions. This ability, in turn, may depend on the ability of the Partnership's subsidiaries to make distributions to it. The ability of the Partnership, its subsidiaries and other entities in which it directly or indirectly holds an equity interest to make such distributions will be subject to, among other things, (i) applicable laws or regulations that may limit the amount of funds available for distribution and (ii) restrictions in relevant debt instruments issued by the Partnership or its subsidiaries and other entities in which it directly or indirectly holds an equity interest.

In certain circumstances, the Partnership will be required to make tax distributions to its unitholders, including us, and the tax distributions that the Partnership will be required to make may be substantial.

Pursuant to the A&R Partnership Agreement, the Partnership will make generally pro rata cash distributions, or tax distributions, to its unitholders, including us, in an amount generally intended to allow the unitholders to satisfy their respective income tax liabilities with respect to their allocable share of the income of the Partnership, based on certain assumptions and conventions, provided that the distribution will be sufficient to allow us to satisfy our actual tax liabilities. Because tax distributions will be made pro rata based on ownership and based on an assumed tax rate, the Partnership could be required to make tax distributions that, in the aggregate, exceed the amount of taxes that the Partnership would have paid if it were taxed on its net income at its effective tax rate.

Funds used by the Partnership to satisfy its tax distribution obligations will not be available for reinvestment in the business. Moreover, the tax distributions the Partnership will be required to make may be substantial and may exceed the unitholder's tax liabilities if the unitholder has an overall effective tax rate that is lower than the assumed rate.

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

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

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

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

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

The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading of our common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our limited trading volume, the concentration of holdings of our common stock, 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.

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

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

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

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

As of March 5, 2021, Juniper beneficially owns 225,481.09 shares of Series A Preferred Stock, which are exchangeable for shares of our common stock at the election of the holder for no additional consideration. Although Juniper is restricted from selling any of its equity securities in the Company and the Partnership prior to July 14, 2021, Juniper may decide to reduce its investment in the Company at any time thereafter. Any such sales of our equity securities, or expectations thereof, could have the effect of depressing the market price for our common stock.

Item 1B Unresolved Staff Comments

None.

Item 2 Properties

As of December 31, 2020, our oil and gas assets were located in Gonzales, Lavaca, Fayette and Dewitt Counties in South Texas.

Facilities

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

Title to Oil and Gas Properties

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

Summary of Oil and Gas Reserves

Proved Reserves

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

	Crude Oil	NGLs	Natural Gas	Oil Equivalents	Standardized Measure	PV10 [1]
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	$ in millions	$ in millions
2020						
Developed						
Producing	36.4	8.0	37.6	50.6		
Non-producing	—	—	—	—		
	36.4	8.0	37.6	50.6		
Undeveloped	62.1	7.6	36.1	75.8		
	98.5	15.6	73.7	126.4	$ 650.3	$ 657.5
Price measurement used	$39.54/Bbl	$7.51/Bbl	$1.99/MMBtu			
2019						
Developed						
Producing	40.1	8.7	41.0	55.6		
Non-producing	0.5	0.2	0.8	0.8		
	40.6	8.9	41.8	56.4		
Undeveloped	58.3	10.3	48.6	76.7		
	98.9	19.2	90.4	133.1	$ 1,488.9	$ 1,600.1
Price measurement used	$55.67/Bbl	$13.36/Bbl	$2.58/MMBtu			
2018						
Developed						
Producing	35.2	6.3	31.8	46.8		
Non-producing	—	—	—	—		
	35.2	6.3	31.8	46.8		
Undeveloped	54.5	11.7	59.7	76.2		
	89.7	18.0	91.5	123.0	$ 1,623.9	$ 1,769.4
Price measurement used	$65.56/Bbl	$23.60/Bbl	$3.10/MMBtu			

[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 of $7.0 million, $111.2 million and $145.5 million for 2020, 2019 and 2018, respectively. We believe that PV10 is a meaningful supplemental disclosure to the Standardized Measure as the PV10 concept is widely used within the industry and by the financial and investment community to evaluate the proved reserves on a comparable basis across companies without regard to the individual owner's unique income tax position. We utilize PV10 to evaluate the potential return on investment in our oil and gas properties as well as evaluating properties for potential purchases and sales.

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

Proved Undeveloped Reserves

The proved undeveloped reserves included in our reserve estimates relate to wells that are forecasted to be drilled within the next five years. The following table sets forth the changes in our proved undeveloped reserves during the year ended December 31, 2020:

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	58.3	10.3	48.6	76.7
Revisions of previous estimates	(19.2)	(4.7)	(22.5)	(27.6)
Extensions and discoveries	29.9	3.2	15.4	35.7
Conversion to proved developed reserves	(6.9)	(1.2)	(5.4)	(9.0)
Proved undeveloped reserves at end of year	62.1	7.6	36.1	75.8

The marginal decrease in our proved undeveloped oil equivalent reserves over the quantities at the end of 2019 is due primarily to the combined effect of largely offsetting changes as described below.

In light of significantly different economic conditions due to the ongoing COVID-19 pandemic and their impact on our capital resources, we undertook a review of our drilling plans and available site inventory that resulted in a substantial shift in the focus of our near-term drilling schedule to our core, oilier prospects. This process resulted in an increase to extensions and discoveries of 35.7 MMBOE that was largely offset by 34.0 MMBOE of negative revisions due primarily to certain wells that are now beyond our five-year drilling window schedule. In addition, our revision of previous estimates reflect: (i) favorable revisions of 6.2 MMBOE attributable to changes in lateral lengths and type curves, (ii) favorable revisions of 0.7 MMBOE due to improved performance partially offset by (iii) 0.3 MMBOE due to a decline in pricing.

During 2020, we incurred capital expenditures of $102.5 million attributable to drilling and completing 21 gross (19.7 net) wells in connection with the conversion of proved undeveloped reserves to proved developed reserves. Our conversion rates for quantities of proved undeveloped reserves were 12 percent, 22 percent and 33 percent in 2020, 2019 and 2018, respectively. The conversion rate decline experienced in 2020 was adversely impacted by the temporary suspension of our drilling and completion program from April through September of 2020 in response to the economic downturn associated with the global COVID-19 pandemic.

Preparation of Reserves Estimates and Internal Controls

The proved reserve estimates were prepared by DeGolyer and MacNaughton, Inc., our independent third party petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see "*Supplemental Information on Oil and Gas Producing Activities (Unaudited)*" in our Notes to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" and the report of DeGolyer and MacNaughton, Inc., dated January 29, 2021, 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, 2020 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 Senior Vice President, Development is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc. Our Senior Vice President, Development has over 25 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from the Colorado School of Mines and is registered by the States of Colorado and Wyoming as a Petroleum Engineer. Our internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation. In addition to conducting these internal reviews and external reserves audits, we also have a Reserves Committee that consists four members of our Board of Directors. This committee provides additional oversight of our reserves estimation and certification process.

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

Oil and Gas Production by Region

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

	Total Sales Volume		
	Year Ended December 31,		
Region	**2020**	**2019**	**2018**
	(MBOE)		
South Texas	8,887	10,121	7,780
Mid-Continent [1]	—	—	165
	8,887	10,121	7,944

	Average Daily Sales Volume		
	Year Ended December 31,		
Region	**2020**	**2019**	**2018**
	(BOEPD)		
South Texas	24,281	27,730	21,314
Mid-Continent [1]	—	—	451
	24,281	27,730	21,765

[1] Mid-Continent operations were sold on July 31, 2018 representing a complete divestiture in which we have no retained interests.

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 sales volume for the periods presented:

	Year Ended December 31,		
	2020	**2019**	**2018**
Average prices:			
Crude oil ($ per Bbl)	$ 36.86	$ 58.33	$ 66.23
NGLs ($ per Bbl)	$ 7.68	$ 11.13	$ 20.99
Natural gas ($ per Mcf)	$ 1.88	$ 2.51	$ 3.08
Aggregate ($ per BOE)	$ 30.47	$ 46.34	$ 55.33
Average production and lifting cost ($ per BOE):			
Lease operating	$ 4.22	$ 4.26	$ 4.52
Gathering processing and transportation	2.48	2.29	2.34
	$ 6.70	$ 6.55	$ 6.86

Significant Fields

Our properties in the Eagle Ford in South Texas, which contain primarily crude oil reserves, represented all of our total equivalent proved reserves as of December 31, 2020.

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

	Year Ended December 31,		
	2020	**2019**	**2018**
Sales volume:			
Crude oil (MBbl)	6,829	7,453	6,050
NGLs (MBbl)	1,165	1,491	944
Natural gas (MMcf)	5,360	7,067	4,713
Total (MBOE)	8,887	10,121	7,780
Percent of total company sales volume	100 %	100 %	98 %
Average prices:			
Crude oil ($ per Bbl)	$ 36.86	$ 58.33	$ 66.24
NGLs ($ per Bbl)	$ 7.68	$ 11.13	$ 21.10
Natural gas ($ per Mcf)	$ 1.88	$ 2.51	$ 3.16
Aggregate ($ per BOE)	$ 30.47	$ 46.34	$ 55.99
Average production and lifting cost ($ per BOE):			
Lease operating	$ 4.22	$ 4.26	$ 4.47
Gathering processing and transportation	2.48	2.29	2.27
	$ 6.70	$ 6.55	$ 6.74

Drilling and Other Exploratory and Development Activities

The following table sets forth the gross and net development wells that we completed (regardless of when drilling was initiated), all of which were in the Eagle Ford in South Texas, during the years indicated and wells that were in progress at the end of each year. There were no exploratory wells drilled in any of the years presented.

	2020		**2019**		**2018**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development						
Productive	23	20.6	48	43.3	53	45.5
Dry hole	—	—	—	—	—	—
Total	23	20.6	48	43.3	53	45.5
Wells in progress at end of year [1]	7	6.3	8	7.3	11	10.2

[1] Includes two gross (1.9 net) wells completing, three gross (2.7 net) wells waiting on completion and two gross (1.7 net) wells being drilled as of December 31, 2020.

Present Activities

As of March 5, 2021, three gross (2.8 net) wells were completing and nine gross (7.1 net) wells were in progress.

Delivery Commitments

We generally sell our crude 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) through 2031 under gathering and transportation agreements with Nuevo Dos Gathering and Transportation, LLC and Nuevo Dos Marketing LLC. Our production and reserves are currently sufficient to fulfill the current 8,000 BOPD delivery commitment under these agreements.

Productive Wells

The following table sets forth our productive wells in which we had a working interest as of December 31, 2020:

	Primarily Oil		Primarily Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	509	429.1	23	22.2	532	451.3

Of the total wells presented in the table above, we are the operator of 520 gross (497 oil and 23 natural gas) and 449.4 net (427.2 oil and 22.2 natural gas) wells. In addition to the above working interest wells, we own overriding royalty interests in 18 gross wells. During 2020, we formally reclassified 23 gross wells to gas from oil with the Texas Railroad Commission.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2020 (in thousands):

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Total acreage	91.0	79.8	7.2	6.5	98.2	86.3

The primary terms of our leases generally range from three to five years, and we do not have any concessions. As of December 31, 2020, 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 (in thousands):

	2021	2022	2023	Thereafter
Expirations by year	1.2	3.1	2.2	—

We anticipate paying options to extend a substantial portion of the acreage scheduled to expire in 2021. We do not believe that the remaining scheduled expirations of our undeveloped acreage will substantially affect our ability or plans to conduct our exploration and development activities.

Item 3 Legal Proceedings

See Note 14 to our Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data.” We are not aware of any material legal or governmental proceedings against us, or threatened to be brought against us, under the various environmental protection statutes to which we are subject.

Item 4 Mine Safety Disclosures

Not applicable.

Part II

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

Market Information

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

Equity Holders

As of February 12, 2021, there were 113 record holders of our common stock.

Dividends

We have not paid nor do we currently have plans to pay any cash dividends on our common stock in the foreseeable future. Furthermore, we are limited in our ability to pay 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 16 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 2020.

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, sales volume and reserves)					
	Successor [1]					Predecessor [1]
	Year Ended December 31,				September 13 Through December 31,	January 1 Through September 12,
	2020	2019	2018	2017	2016	2016
Statements of Operations and Other Data:						
Revenues [2]	$ 273,268	$ 471,216	$ 440,832	$ 160,054	$ 39,003	$ 94,310
Operating income (loss) [3, 4]	$ (369,175)	$ 176,821	$ 208,755	$ 51,872	$ 11,413	$ (20,867)
Net income (loss) [4, 5]	$ (310,557)	$ 70,589	$ 224,785	$ 32,662	$ (5,296)	$ 1,054,602
Preferred stock dividends	$ —	$ —	$ —	$ —	$ —	$ 5,972
Income (loss) attributable to common shareholders [5]	$ (310,557)	$ 70,589	$ 224,785	$ 32,662	$ (5,296)	$ 1,048,630
Income (loss) per common share, basic	$ (20.46)	$ 4.67	$ 14.93	$ 2.18	$ (0.35)	$ 11.91
Income (loss) per common share, diluted	$ (20.46)	$ 4.67	$ 14.70	$ 2.17	$ (0.35)	$ 8.50
Weighted-average shares outstanding:						
Basic	15,176	15,110	15,059	14,996	14,992	88,013
Diluted	15,176	15,126	15,292	15,063	14,992	124,087
Dividends declared per share	$ —	$ —	$ —	$ —	$ —	$ —
Cash provided by operating activities	$ 221,778	$ 320,194	$ 272,132	$ 81,710	$ 30,774	$ 30,247
Cash paid for capital expenditures	$ 168,565	$ 362,743	$ 430,592	$ 115,687	$ 4,812	$ 15,359
Total sales volume (MBOE)	8,887	10,121	7,944	3,779	1,039	3,346

	December 31,					September 12,
	2020	2019	2018	2017	2016	2016
Balance Sheet and Other Data:						
Property and equipment, net	$ 723,549	$ 1,120,425	$ 927,994	$ 529,059	$ 247,473	$ 253,510
Total assets	$ 907,326	$ 1,218,238	$ 1,068,954	$ 629,597	$ 291,686	$ 333,974
Long-term debt, net	$ 509,497	$ 555,028	$ 511,375	$ 265,267	$ 25,000	$ 75,350
Shareholders' equity	$ 212,838	$ 520,745	$ 447,355	$ 221,639	$ 185,548	$ 190,895
Actual shares outstanding at period-end	15,200	15,136	15,081	15,019	14,992	14,992
Proved reserves as of December 31, (MMBOE)	126	133	123	73	49	N/A

[1] Upon our emergence from bankruptcy, we adopted and applied fresh start accounting. Accordingly, our financial statements for periods after September 12, 2016 are not comparable to those prior to that date. Financial information for the periods up to and including September 12, 2016 are referred to herein as those of the "Predecessor" while those beginning on September 13, 2016 and all periods thereafter are referenced as those of the "Successor."

[2] Revenues for the years ended after December 31, 2017 reflect the application of Accounting Standards Codification, or ASC, Topic 606, *Revenues from Contracts with Customers*, or ASC Topic 606. The adoption of ASC Topic 606 impacts the presentation and comparability of NGL product revenues between the years beginning after December 31, 2017 with those years ending on that date and all prior periods. See Note 2 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[3] Operating income (loss) for the year ended December 31, 2020 reflects the application of Accounting Standards Update, or ASU, No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, or ASU 2016-13. The adoption of ASU 2016-13 impacts the presentation and comparability of Other revenues, net between the year ended December 31, 2020 with all prior periods. Operating income (loss) for the year ended December 31, 2019 reflects the application of ASC Topic 842, *Leases*, or ASC Topic 842. The adoption of ASC Topic 842 impacts the presentation and comparability of lease expense between the years ended December 31, 2020 and 2019 with all prior periods. See "*Presentation of Financial Information and Changes in Accounting Principles*" included in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes 2 and 5 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[4] Includes impairments of our oil and gas properties of $391.8 million for the year ended December 31, 2020.

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

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Part II, Item 8, “Financial Statements and Supplementary Data.” All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Also, due to the combination of different units of volumetric measure and the number of decimal places presented and rounding, certain results may not calculate explicitly from the values presented in the tables. Certain statistics for years ended December 31, 2019 and 2018 have been reclassified to conform to the 2020 presentation.

Overview and Executive Summary

We are an independent oil and gas company focused on the onshore exploration, development and production of crude oil, NGLs and natural gas. Our current operations consist of drilling unconventional horizontal development wells and operating our producing wells in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

Industry Environment and Recent Operating and Financial Highlights

Commodity Price and Other Economic Conditions

The global public health crisis associated with the novel coronavirus, or COVID-19, has, and is anticipated to continue to have, an adverse effect on the global economy, which may be prolonged, and has resulted in travel restrictions, business closures, limitations to person-to-person contact and the institution of quarantining and other restrictions on movement in many communities. These restrictions resulted in a dramatic decline in the demand for energy in 2020, which directly impacted our industry and the Company. In addition, global crude oil prices experienced significant decline since the beginning of 2020 as a result of the dual impact of demand deterioration and market oversupply caused by disagreements between the Organization of the Petroleum Exporting Countries, or OPEC, and Russia, together with OPEC, collectively OPEC+, with respect to production curtailments. OPEC+ ultimately agreed to specified reductions in production in the Spring of 2020 which, for the most part, held for the remainder of the year and were supplemented by additional voluntary downward adjustments, led primarily by Saudi Arabia. Collectively these curtailments have contributed to a relative stabilization of commodity prices and rebalancing of the global crude oil markets by the end of 2020.

Notwithstanding the relative improvement in global market stability, as a result of several factors including rising infection rates at the beginning of 2021, mutating strains of the virus, the return of stricter lockdown measures and logistical challenges in vaccine distribution, among others, a return to pre-COVID 19 levels of economic activity remain uncertain in their magnitude and eventual timing. Nonetheless, OPEC+ indicated in their January 2021 meeting a commitment to gradually return limited production to the market with the pace being determined by market conditions. An additional meeting is scheduled for early March of 2021 to monitor conditions and progress.

A significant decline in domestic drilling by U.S. producers began in mid-March 2020 and continued through most of the second half of the year. The overall economic decline had an adverse impact on the entire industry, but particularly on smaller upstream producers with limited financial resources as well as oilfield service companies. While a modest recovery in activity began in the fourth quarter of 2020, including a resumption of our own drilling program, domestic supply and demand imbalances continue to stress the market which is further exacerbated by capacity limitations associated with storage, pipeline and refining infrastructure, particularly within the Gulf Coast region.

While there exists encouraging signs for continued recovery due to the aforementioned vaccine development as well as a commitment by the new U.S. Administration to prioritize economic relief efforts, the relative success of such efforts is difficult to predict with respect to timing and the resulting economic impact. Accordingly, the combined effect of the global and domestic factors discussed herein is anticipated to continue to contribute to overall volatility within the industry generally and to our operations specifically.

The combined effect of COVID-19 and the continuing energy industry instability has led to significant volatility in NYMEX WTI crude oil prices throughout 2020 and into 2021. In the beginning of January 2020, prices were approximately $62 per barrel and ended the year at approximately $48 per barrel for a decrease of approximately 23 percent. Prices have continued to rise and since the beginning of 2021 have ranged from approximately $47 to $66 per barrel through March 5, 2021. Despite this recovery, overall crude oil pricing will remain subject to significant volatility consistent with the global and domestic factors discussed above.

During 2020, we initiated several actions to mitigate the anticipated adverse economic conditions for the immediate future and to support our financial position and liquidity. The more significant actions that we took during that time included: (i) temporarily suspending our drilling program from April through September 30, 2020, (ii) curtailing production through selected well shut-ins for a period of several weeks in April and May, (iii) securing additional crude oil storage capacity, (iv) substantially expanding the scope and range of our commodity derivatives portfolio, (v) utilizing certain provisions of the Coronavirus Aid, Relief and Economic Security Act, or CARES Act, and related regulations, the most significant of which resulted in the receipt in June 2020 of an accelerated refund of our remaining refundable alternative minimum tax, or AMT, credit carryforwards in the amount of $2.5 million and (vi) eliminating annual cost-of-living and similar adjustments to our salaries and wages for 2020, and a limited RIF during the third quarter of 2020.

These actions are described in greater detail in the discussions for *Key Developments* that follow as well as Notes 2, 6, 10 and 14 to the Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data.”

Capital Expenditures and Development Progress

We temporarily suspended our drilling program from April through September 2020. During that period, we selectively completed and turned our remaining eight gross (7.6 net) wells to sales that were drilled prior to the program suspension. As a result of a modest improvement in commodity prices relative to the first half of 2020, we resumed a limited drilling program in October 2020 with one rig and expanded to two rigs later in November 2020 continuing into 2021.

During 2020, we incurred capital expenditures of approximately $130.6 million with 96 percent directed to drilling and completion projects through which a total of 23 gross (20.6 net) wells were drilled, completed and turned to sales.

Sequential Quarterly Analysis

The following summarizes our key operating and financial highlights for the three months ended December 31, 2020 with comparison to the three months ended September 30, 2020 as presented in the table that follows. The year-over-year highlights for 2020 and 2019 are addressed in further detail in the discussions for *Financial Condition* and *Results of Operations* that follow.

- Daily sales volume decreased approximately 12 percent to 21,502 BOEPD, from 24,295 BOEPD due primarily to the effect of natural well declines in the absence of an active drilling program that did not resume until October of 2020 as well as the impact of turning only two gross (2.0 net) wells to sales during the fourth quarter of 2020 as compared to five gross (4.8 net) wells during the third quarter of 2020. Total sales volume declined approximately 12 percent to 1,978 MBOE from 2,235 MBOE due to the aforementioned natural well declines and drilling program timing. While overall sales volume declined, the percentage of crude oil volume sold increased to 78 percent from 76 percent during the fourth quarter of 2020.
- Product revenues decreased three percent to $66.5 million from $68.6 million due primarily to nine percent lower crude oil volume, or $5.7 million, partially offset by six percent higher crude oil prices, or $3.5 million. NGL revenues declined six percent due to 19 percent lower volume, or $0.6 million, partially offset by 16 percent higher prices, or $0.4 million. Natural gas revenues increased 10 percent due to a 36 percent increase in pricing, or $0.8 million, partially offset by a 19 percent decrease in volume, or $0.5 million.
- Production and lifting costs (consisting of LOE and GPT) increased on an absolute and per unit basis to $14.8 million and $7.49 per BOE from $14.0 million and $6.28 per BOE due primarily to higher preventive and other previously deferred maintenance and workover costs, higher environmental compliance costs as well as higher crude oil storage costs partially offset by lower volumetric and variable-based costs attributable to the overall lower sales volume.
- Production and ad valorem taxes decreased on an absolute and per unit basis to $3.5 million and $1.75 per BOE from $4.4 million and $1.95 per BOE, respectively, due primarily to the effect of substantially lower estimated valuations for ad valorem tax assessments as well as the effect of overall lower product revenues.
- G&A expenses increased on an absolute and per unit basis to $10.0 million and $5.05 per BOE from $8.6 million and $3.84 per BOE, respectively, due primarily to higher costs incurred in connection with the Juniper Transaction.
- Our DD&A, decreased on an absolute and per unit basis to $25.8 million and $13.03 per BOE from $37.0 million and $16.57 per BOE due primarily to higher reserve quantity estimates and, to a lesser extent, the reduction to costs attributable to the impairment recorded during the third quarter of 2020.
- In the fourth quarter of 2020, we recorded an impairment of our oil and gas properties of $120.3 million as the unamortized cost of our oil and gas properties, net of deferred income taxes, exceeded the sum of discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes, or the Ceiling Test. The impairment is primarily attributable to a decline in the trailing twelve-month average prices of crude oil, NGLs and natural gas. We recorded an impairment of $236.0 million as a result of similar conditions in the third quarter of 2020.
- Due to the combined impact of the matters noted in the bullets above, we incurred an operating loss of $107.4 million in the fourth quarter of 2020 compared to $230.6 million in the third quarter of 2020.

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

	(in thousands except per unit measurements, sales volume, wells and reserves)				
	Three Months Ended				
	December 31,	September 30,	Year Ended December 31,		
	2020	2020	2020	2019	2018
Total sales volume (MBOE) [1]	1,978	2,235	8,887	10,121	7,944
Average daily sales volume (BOEPD) [1]	21,502	24,295	24,281	27,730	21,765
Crude oil sales volume (MBbl) [1]	1,538	1,691	6,829	7,453	6,077
Crude oil sold as a percent of total [1]	78 %	76 %	77 %	74 %	76 %
Product revenues	$ 66,491	$ 68,614	$ 270,792	$ 469,035	$ 439,530
Crude oil revenues	$ 61,009	$ 63,227	$ 251,741	$ 434,713	$ 402,485
Crude oil revenues as a percent of total	92 %	92 %	93 %	93 %	92 %
Realized prices:					
Crude oil ($ per Bbl)	$ 39.66	$ 37.39	$ 36.86	$ 58.33	$ 66.23
NGL ($ per Bbl)	$ 10.71	$ 9.20	$ 7.68	$ 11.13	$ 20.99
Natural gas ($ per Mcf)	$ 2.45	$ 1.80	$ 1.88	$ 2.51	$ 3.08
Aggregate ($ per BOE)	$ 33.61	$ 30.70	$ 30.47	$ 46.34	$ 55.33
Prices, adjusted for derivatives:					
Crude oil ($ per Bbl)	$ 48.84	$ 48.28	$ 50.55	$ 56.92	$ 73.21
Natural gas ($ per Mcf)	$ 1.95	$ 1.88	$ 1.88	$ 2.51	$ 3.08
Aggregate ($ per BOE)	$ 40.46	$ 38.99	$ 40.98	$ 45.30	$ 60.67
Production and lifting costs ($ per BOE):					
Lease operating	$ 4.83	$ 3.70	$ 4.22	$ 4.26	$ 4.52
Gathering, processing and transportation	$ 2.66	$ 2.58	$ 2.48	$ 2.29	$ 2.34
Production and ad valorem taxes ($ per BOE)	$ 1.75	$ 1.95	$ 1.87	$ 2.77	$ 2.96
General and administrative ($ per BOE) [2]	$ 5.05	$ 3.84	$ 3.80	$ 2.52	$ 3.28
Depreciation, depletion and amortization ($ per BOE)	$ 13.03	$ 16.57	$ 15.83	$ 17.25	$ 16.11
Capital expenditure program costs [3]	$ 32,627	$ 8,042	$ 130,608	$ 355,851	$ 418,951
Cash provided by operating activities [4]	$ 32,055	$ 60,828	$ 221,778	$ 320,194	$ 272,132
Cash paid for capital expenditures [5]	$ 29,535	$ 26,183	$ 168,565	$ 362,743	$ 430,592
Cash and cash equivalents at end of period	$ 13,020	$ 20,516	$ 13,020	$ 7,798	$ 17,864
Debt outstanding, net of discount and issue costs, at end of period [6]	$ 509,497	$ 518,858	$ 509,497	$ 555,028	$ 511,375
Credit available under credit facility at end of period [7]	$ 35,200	$ 50,200	$ 35,200	$ 137,200	$ 128,600
Net development wells drilled and completed	2.0	4.8	20.6	43.3	45.5
Proved reserves at the end of the period (MMBOE)	126	N/A	126	133	123

[1] All volumetric statistics presented above represent volumes of commodity production that were sold during the periods presented. Volumes of crude oil physically produced in excess of volumes sold are placed in temporary storage to be sold in subsequent periods.

[2] Includes combined amounts of $1.93 and $1.20 per BOE for the three months ended December 31, 2020 and September 30, 2020, respectively, and $1.09, $0.48 and $1.11 per BOE for the years ended December 31, 2020, 2019 and 2018, respectively, attributable to share-based compensation and significant special charges, comprised of organizational restructuring and acquisition, divestiture and strategic transaction costs, including costs attributable to the Juniper Transaction during the 2020 periods, as described in the discussion of "*Results of Operations - General and Administrative* " that follows.

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

[4] Includes net cash received for derivative settlements and premiums (paid) received, net of $12.8 million and $6.4 million for the three months ended December 31, 2020 and September 30, 2020, respectively, and net cash received (paid) for derivative settlements of $78.1 million, $(4.1) million and $(48.3) million for the years ended December 31, 2020, 2019 and 2018, respectively. Reflects changes in operating assets and liabilities of $(12.9) million and $17.8 million for the three months ended December 31, 2020 and September 30, 2020, respectively, and $4.1 million, $0.2 million and $(2.8) million for the years ended December 31, 2020, 2019 and 2018, respectively.

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

[6] Represents amounts net of unamortized discount and deferred issue costs of $4.9 million, $5.5 million $7.4 million and $9.6 million as of December 31, 2020, September 30, 2020, December 31, 2019 and December 31, 2018, respectively.

[7] The borrowing base under the Credit Facility was $375 million as December 31, 2020 with availability further limited to a maximum of $350 million.

Key Developments

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

Strategic Investment by Juniper

In January 2021, we consummated the previously announced Juniper Transactions whereby affiliates of Juniper contributed $150 million in cash and certain oil and gas assets in Lavaca and Fayette Counties in Texas in exchange for a combination of shares of Series A Preferred Stock of the Company and Common Units of a wholly owned subsidiary. The Juniper Transactions, which were effectuated through an up-C structure, represent a change in control of the Company whereby Juniper now controls approximately 60 percent of the economic and voting interests of the Company. We incurred a total of $18.5 million in transaction and securities issuance costs associated with the Juniper Transactions including $5.0 million in 2020 as well as an additional $13.5 million in January 2021. For additional information regarding the Juniper Transactions, see Part I, Item 1, "Business" and Note 2 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Amendments to Credit Facility and Affirmation of Borrowing Base

In January 2021, we entered into the Ninth Amendment permitting the Juniper Transactions and affirming our borrowing base at $375 million with borrowings limited to a maximum of $350 million. In addition, the Ninth Amendment provides for: (i) certain minimum hedging conditions, which were initially satisfied in February 2021, allowing for a borrowing base holiday until Fall 2021 assuming we continue to satisfy the conditions, (ii) introduces a first lien leverage ratio covenant of 2.50 times, tested quarterly and (iii) permits amortization payments of up to $1.875 million per quarter to be made under the Second Lien Facility until January 2022 if no default exists both before and after giving effect to the payments and thereafter using available free cash flow upon the satisfaction of certain conditions (including maintaining a leverage ratio of 2.00 to 1.00 and availability of at least 25% under the Credit Facility after giving pro forma effect to the payment). For additional information regarding the Ninth Amendment see the discussion of *Financial Condition* that follows and Note 9 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." Concurrent with the Ninth Amendment, we paid down $80.5 million of outstanding borrowings under the Credit Facility plus accrued interest of $0.1 million which was funded with the proceeds from the Juniper Transaction. We incurred and capitalized $0.4 million of issue and other costs associated with the Ninth Amendment in January 2021.

Amendment to the Second Lien Facility

On November 2, 2020, we entered into the Second Lien Amendment which became effective upon the Closing of the Juniper Transactions. The Second Lien Amendment (1) extends the maturity date of the Second Lien Facility to September 29, 2024, (2) increases the margin applicable to advances under the Second Lien Facility as further described below; (3) impose certain limitations on capital expenditures, acquisitions and investments if the Asset Coverage Ratio (as defined therein) at the end of any fiscal quarter is less than 1.25 to 1.00 and (4) requires maximum and, in certain circumstances as described therein, minimum hedging arrangements.

Under the Second Lien Amendment, the Company is required to make quarterly amortization payments equal to $1,875,000 and 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 8.25% or (b) a customary London interbank offered rate plus an applicable margin of 7.25%; provided that the applicable margin will increase to 9.25% and 8.25% respectively during any quarter in which the quarterly amortization payment is not made.

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 Eurodollar loans): from January 15, 2021 through January 14, 2022, 102% of the amount being prepaid, from January 15, 2022 through January 14, 2023, 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: from January 15, 2021 through January 14, 2023, 102% of the amount being prepaid, from January 15, 2023 through January 14, 2024, 101% of the amount being prepaid; and thereafter, no premium.

Additionally, on the Closing Date, we entered into the Omnibus Amendment to the Second Lien Facility (the "Omnibus Amendment") to, among other things, effectuate the release of the Company from its guarantee of the obligations of the Borrower and its grant of a security interest in its assets.

Additional restrictions and other qualifications associated with the Second Lien Facility, as amended by the Second Lien Amendment and the Omnibus Amendment, or the Amended Second Lien Facility, are described in the discussion of *Financial Condition* that follows and Note 9 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." We paid down $50.0 million of outstanding loans under the Amended Second Lien Facility plus accrued interest of $0.2 million attributable to lenders and $1.3 million including accrued interest to a non-consenting lender in January 2021 which was funded with the proceeds from the Juniper Transaction. We incurred and capitalized $1.4 million of issue and other costs and wrote-off $1.3 million of unamortized issuance costs in connection with the Second Lien Amendment in January 2021.

Development Plans and Production

In October 2020, we resumed a limited drilling and completion program on a pad-to-pad basis and are currently drilling with two operated rigs. During December 2020, we made prepayments of $13.6 million for drilling and completion materials and services securing locked in rates or discounts in advance of the program for the first quarter of 2021.

We completed and turned two gross (2.0 net) and 23 gross (20.6 net) wells to sales during the quarter and year ended December 31, 2020, respectively. Subsequent to December 31, 2020, we turned an additional five gross (4.5 net) wells to sales through March 5, 2021. As of March 5, 2021, three gross (2.8 net) wells were completing and nine gross (7.1 net) wells were in progress.

Total sales volume for the quarter and year ended December 31, 2020 was 1,978 MBOE and 8,887 MBOE, or 21,502 and 24,281 BOEPD, with approximately 78 percent and 77 percent, or 1,538 MBbls and 6,829 MBbls, of sales volume from crude oil, 12 and 13 percent from NGLs and 10 percent for both periods each from natural gas, respectively.

As of March 5, 2021, we had approximately 102,100 gross (90,100 net) acres in the Eagle Ford, net of expirations. Approximately 92 percent of our acreage is held by production and substantially all is operated by us.

Executive Transition

In August 2020, we appointed Darrin Henke our new president and chief executive officer, or CEO, and director following the retirement of John Brooks. We incurred incremental G&A costs, in connection with Mr. Henke's appointment and Mr. Brooks' separation as described in the discussion for *Results of Operations* that follow.

On January 15, 2021, we announced the departure of Benjamin A. Mathis, Senior Vice President, Operations & Engineering, effective January 4, 2021. Separately, we also announced the appointment of Julia Gwaltney as Senior Vice President, Development, effective January 5, 2021.

In connection with the Juniper Transactions, five new members were appointed to our Board of Directors including: (i) Edward Geiser - Managing Partner of Juniper Capital, (ii) Kevin Cumming - Partner of Juniper Capital, (iii) Tim Gray - General Counsel and Chief Compliance Officer of Juniper Capital, (iv) Joshua Schmidt - Managing Director of Juniper Capital and (v) Temitope Ogunyomi - Director of Juniper Capital.

Actions to Address the Economic Impact of COVID-19 and Industry Decline

During 2020, we initiated and pursued several actions to mitigate the adverse economic conditions and to support our financial position, liquidity and the efficient continuity of our operations as follows:

Drilling Program. We suspended our drilling program beginning in April 2020 through September 2020. See Note 14 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information.

Production Curtailment. In April 2020, we shut-in production on selected wells for a period of several weeks extending through mid-May 2020.

Crude Oil Storage. We secured supplemental storage capacity for our crude oil production primarily on a month-to-month basis. See Note 14 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for additional information.

Derivatives. We substantially expanded the scope and range of our commodity derivatives portfolio during the early stages of the domestic COVID-19 health crisis. For the year ended December 31, 2020, we received $80.3 million in net cash proceeds from settlements, net of premiums, of our commodity derivatives. A portion of these proceeds were received in the second and third quarters of 2020 from contracts that were either restructured or put into place early in March and April of 2020.

Federal Relief. We utilized a number of liquidity and income tax measures made available under the CARES Act and related regulations, the most significant of which was the application for an accelerated refund of our remaining alternative minimum tax, or AMT, credits of $2.5 million, which was received in June 2020, that would have otherwise been payable to us over the next two years.

Working Capital. We are continuing our increased diligence in collecting and managing our portfolio of joint venture receivables.

Cost Containment. We eliminated annual cost-of-living and similar adjustments to our salaries and wages for 2020, and in July 2020, we completed a limited RIF. We incurred and paid employee termination and severance benefits in connection with the limited RIF and those costs have been included in G&A. In addition, we implemented protocols and systems, designed to keep our employees safe and our operations at desired capacity during the COVID-19 pandemic.

Commodity Hedging Program

As of February 25, 2021, we have hedged a portion of our estimated future crude oil, natural gas and ethane production through the first half of 2023. The following table, inclusive of January and February 2021 production months, summarizes our hedge positions for the periods presented:

	1Q2021	2Q2021	3Q2021	4Q2021	1Q2022	2Q2022	3Q2022	4Q2022	1Q2023	2Q2023
NYMEX WTI Crude Swaps										
Average Volume Per Day (barrels)	3,889	3,297	815	815						
Weighted Average Swap Price ($/barrel)	$ 54.38	$ 55.89	$ 45.54	45.54						
NYMEX WTI Crude Collars										
Average Volume Per Day (barrels)	10,278	12,088	10,870	8,152	5,417	4,533	4,484	4,484	2,917	2,855
Weighted Average Purchased Put Price ($/barrel)	$ 40.92	$ 43.82	$ 41.80	$ 40.40	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Weighted Average Sold Call ($/barrel)	$ 46.51	$ 54.67	$ 56.09	$ 52.10	$ 53.49	$ 52.47	$ 52.47	$ 52.47	$ 50.00	$ 50.00
NYMEX WTI Purchased Puts										
Average Volume Per Day (barrels)	1,667									
Weighted Average Purchased Put Price ($/barrel)	$ 55.00									
NYMEX WTI Sold Puts										
Average Volume Per Day (barrels)	556	4,945	5,707	5,707						
Weighted Average Sold Put ($/barrel)	$ 26.50	$ 29.83	$ 35.14	35.14						
MEH-NYMEX WTI Crude Basis Swaps										
Average Volume Per Day (barrels)	8,889									
Weighted Average Swap Price ($/barrel)	$ 1.16									
NYMEX WTI Crude CMA Roll Basis Swaps										
Average Volume Per Day (barrels)	16,111	18,132	17,935	17,935						
Weighted Average Swap Price ($/barrel)	$ (0.11)	$ 0.17	$ 0.17	$ 0.17						
NYMEX HH Collars										
Average Volume Per Day (MMBtus)	10,000	9,890	9,783	9,783						
Weighted Average Purchased Put Price ($/MMBtu)	$ 2.607	$ 2.607	$ 2.607	$ 2.607						
Weighted Average Sold Call ($/MMBtu)	$ 3.117	$ 3.117	$ 3.117	$ 3.117						
NYMEX HH Sold Puts										
Average Volume Per Day (MMBtus)	6,667	6,593	6,522	6,522						
Weighted Average Sold Put Strike ($/MMBtu)	$ 2.000	$ 2.000	$ 2.000	$ 2.000						
OPIS Mt Belv Ethane Swaps										
Average Volume per Day (Gallons)		36,264	35,870							
Weighted Average Fixed Price ($/Gal)		$ 0.2263	$ 0.2288							

Financial Condition

Liquidity

Our primary sources of liquidity include cash on hand, cash provided by operating activities and borrowings under the Credit Facility. The Credit Facility provides us with up to $1.0 billion in borrowing commitments. The current borrowing base under the Credit Facility is $375 million with availability further limited to a maximum of $350 million. As of March 5, 2021, we had $120.7 million of availability under the Credit Facility.

Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for crude oil, NGL and natural gas products, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity and other supply chain dynamics, among other factors. All of these factors have been negatively impacted by the continuing COVID-19 pandemic and the related instability in the global energy markets. In order to mitigate this volatility, we entered into derivative contracts with a number of financial institutions, all of which are participants in the Credit Facility, hedging a portion of our estimated future crude oil and natural gas production through the end of 2023. 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.

Capital Resources

Under our 2021 capital program, we anticipate capital expenditures, excluding acquisitions, of up to $240 million with approximately 98 percent of capital being directed to drilling and completions. We plan to fund our 2021 capital program and our operations for the next twelve months primarily with cash on hand, cash from operating activities, including net receipts from derivative settlements and, to the extent necessary, supplemental borrowings under the Credit Facility. Based upon current price and production expectations for 2021, we believe that our cash from operating activities and borrowings under our Credit Facility, as necessary, will be sufficient to fund our capital spending and operations for at least the next twelve months; however, future cash flows are subject to a number of variables and the length and magnitude of the current global economic slowdown associated with the COVID-19 pandemic and related instability in the global energy markets.

For a detailed analysis of our historical capital expenditures, see the "*Cash Flows*" discussion that follows.

Cash on Hand and Cash From Operating Activities. For additional information and an analysis of our historical cash flows from operating activities, see the "*Cash Flows*" discussion that follows.

Credit Facility Borrowings. During 2020, we repaid $48 million, net of borrowings, under the Credit Facility, including repayments of $10 million during the quarter ended December 31, 2020. We also repaid $80.5 million in January 2021 concurrent with the Ninth Amendment and an additional $5 million in February 2021. 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			
	End of Period	Weighted-Average	Maximum	Weighted-Average Rate
Three months ended December 31, 2020	$ 314,400	$ 315,270	$ 324,400	3.40 %
Year ended December 31, 2020	$ 314,400	$ 353,665	$ 399,400	3.55 %

Proceeds from Sales of Assets. We continually evaluate potential sales of assets, including certain non-strategic oil and gas properties and 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 Markets 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. We maintain an effective shelf registration statement to allow for optionality. As more fully described in Part I, Item 1. "Business," the discussion of Key Developments previously and Note 2 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data," the Juniper Transaction resulted in the issuance of Series A Preferred Stock and the Common Units in January 2021.

Cash Flows

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

	Year Ended December 31, 2020	Year Ended December 31, 2019
Cash flows from operating activities		
Operating cash flows, net of working capital changes	$ 171,502	$ 356,321
Crude oil derivative settlements and premiums received (paid), net	80,329	(4,136)
Natural gas settlements paid, net	(32)	—
Interest rate swap settlements paid, net	(2,210)	—
Interest payments, net of amounts capitalized	(27,333)	(32,398)
Income tax refunds	2,471	2,471
Organizational restructuring costs, including severance benefits, paid	(1,446)	—
Strategic transaction costs paid	(1,503)	(2,064)
Net cash provided by operating activities	221,778	320,194
Cash flows from investing activities		
Acquisitions, net	—	(6,516)
Capital expenditures	(168,565)	(362,743)
Proceeds from sales of assets, net	87	215
Net cash used in investing activities	(168,478)	(369,044)
Cash flows from financing activities		
Proceeds (repayments) under credit facility, net	(48,000)	41,400
Debt issuance costs paid	(78)	(2,616)
Net cash provided by financing activities	(48,078)	38,784
Net increase (decrease) in cash and cash equivalents	$ 5,222	$ (10,066)

Cash Flows from Operating Activities. The decrease of $98.4 million in net cash from operating activities for 2020 compared to 2019 was primarily attributable to the substantial decline in commodity prices resulting from the adverse impact of COVID-19 on the global economy and general instability in the global energy markets as well as the effect of 12 percent lower total sales volume, each of which substantially decreased our realized product revenues. In addition, in 2020 we incurred and paid costs for organizational restructuring activities, including severance benefits. These adverse impacts on cash provided by operating activities were partially offset by: (i) substantially higher receipts from our crude oil derivatives settlements, net of premiums during 2020, (ii) lower interest payments, net of interest rate swap settlements, due to substantially lower weighted-average variable rates despite higher outstanding borrowings in 2020, (iii) lower strategic transaction costs paid in 2020 as compared to similar costs paid in 2019, (v) the beneficial impact in 2020 of cost containment efforts in both our operations and administrative functions including lower discretionary maintenance, lower contract labor and cost deferrals consistent with lower levels of business activity, the elimination of cost-of-living and similar adjustments to our salaries and wages and reduced employee headcount and (vi) improved working capital management.

Cash Flows from Investing Activities. As illustrated in the tables below, our cash payments for capital expenditures were significantly lower during 2020 as compared to 2019, due primarily to the suspension of the drilling program for a substantial portion of 2020, partially offset by prepayments of $13.6 million in December 2020 for certain tubular and well materials and drilling and completion materials and services to lock in prices and secure discounts in advance of the program for the first quarter of 2021. The cash payments for capital expenditures for 2019 also reflect refunds of $3.8 million received for sales and use taxes that were applicable to capital expenditures in prior years. In 2019, we paid our joint working interest partners $6.5 million for the acquisition of working interests in certain properties for which we are the operator. In addition, we received insignificant proceeds from the sale of scrap tubular and well materials in both years.

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

	Year Ended December 31,	
	2020	2019
Drilling and completion	$ 125,626	$ 344,542
Lease acquisitions and other land-related costs	3,447	3,433
Geological, geophysical (seismic) and delay rental costs	342	363
Pipeline, gathering facilities and other equipment, net	1,193	7,513
	$ 130,608	$ 355,851

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

	Year Ended December 31,	
	2020	2019
Total capital expenditures program costs (from above)	$ 130,608	$ 355,851
Decrease in accrued capitalized costs	18,671	3,602
Less:		
Transfers from tubular inventory and well materials	(8,057)	(10,971)
Sales & use tax refunds received and applied to property accounts	—	(3,816)
Other, net	—	(115)
Add:		
Prepayments for drilling and completion materials and services	13,608	—
Tubular inventory and well materials purchased in advance of drilling	8,924	9,967
Capitalized internal labor	2,067	4,089
Capitalized interest	2,744	4,136
Total cash paid for capital expenditures	$ 168,565	$ 362,743

Cash Flows from Financing Activities. During 2020, we had borrowings of $51.0 million and made repayments of $99.0 million under the Credit Facility while 2019 included borrowings of $76.4 million and repayments of $35.0 million. The borrowings were utilized to fund a portion of our capital program in both years as well as the aforementioned acquisition of working interests in 2019. We also paid $0.1 million and $2.6 million of debt issue costs in 2020 and 2019, respectively, in connection with amendments to the Credit Facility.

Capitalization

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

	December 31,	
	2020	2019
Credit Facility borrowings	$ 314,400	$ 362,400
Second Lien Facility term loans, net of original issue discount and issuance costs	195,097	192,628
Total debt	509,497	555,028
Shareholders' equity	212,838	520,745
Total capitalization	$ 722,335	$ 1,075,773
Debt as a % of total capitalization	71 %	52 %

Credit Facility. The Credit Facility provides for a $1.0 billion revolving commitment and a $375 million borrowing base including a $25 million sublimit for the issuance of letters of credit. Availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base; however, outstanding borrowings under the Credit Facility are limited to a maximum of $350 million until at least the next redetermination of the borrowing base. The borrowing base under the Credit Facility is redetermined semi-annually, generally in the Spring and Fall of each year. Additionally, we and the Credit Facility lenders may, upon request, initiate a redetermination at any time during the six-month period between scheduled redeterminations. Certain minimum hedging and other conditions included in the Ninth Amendment were initially satisfied in February 2021 which allow for a borrowing base holiday until Fall 2021 assuming we continue to satisfy the conditions. The Credit Facility is available to us for general corporate purposes, including working capital. The Credit Facility is scheduled to mature in May 2024. We had $0.4 million in letters of credit outstanding as of December 31, 2020 and 2019.

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 1.50% to 2.50%, determined based on the utilization level under the Credit Facility or (b) a Eurodollar rate, including LIBOR through 2021, plus an applicable margin ranging from 2.50% to 3.50%, determined based on the utilization level 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 Eurodollar 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, 2020, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 3.40%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by the Partnership and all of its subsidiaries (excluding the borrower subsidiary), or the Guarantor Subsidiaries. The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. There are no significant restrictions on the ability of the borrower or of 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 subsidiaries' assets.

Second Lien Facility. In accordance with the Second Lien Amendment, the maturity date of the Second Lien Facility was extended to September 29, 2024.

The Company is required to make quarterly amortization payments of $1.875 million and 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 8.25% or (b) a Eurodollar rate, including LIBOR through 2021, with a floor of 1.00%, plus an applicable margin of 7.25%; provided that the applicable margin will increase to 9.25% and 8.25%, respectively, during any quarter in which the quarterly amortization payment is not made. As of December 31, 2020, the actual interest rate of outstanding borrowings under the Second Lien Facility was 8.00%. 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 Eurodollar 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 Eurodollar loans): from January 15, 2021 through January 14, 2022, 102% of the amount being prepaid, from January 15, 2022 through January 14, 2023, 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: from January 15, 2021 through January 14, 2023, 102% of the amount being prepaid, from January 15, 2023 through January 14, 2024, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of our subsidiaries' assets with lien priority subordinated to the liens securing the Credit Facility. The obligations under the Second Lien Facility are guaranteed by the Partnership and the Guarantor Subsidiaries.

Covenant Compliance. The Credit Facility requires us to maintain (1) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset) of 1.00 to 1.00, (2) a maximum leverage ratio (consolidated indebtedness to EBITDAX, each as defined in the Credit Facility), in each case measured as of the last day of each fiscal quarter of 3.50 to 1.00. and (3) a maximum first lien leverage ratio (consolidated secured indebtedness to adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses, both as defined in the Credit Facility), measured as of the last day of each fiscal quarter, of 2.50 to 1.00.

The Credit Facility and Second Lien Facility also contain 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), limitations on capital expenditures, investments, the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants. In addition, the Credit Facility contains certain anti-cash hoarding provisions, including the requirement to repay outstanding loans and cash collateralize outstanding letters of credit on a weekly basis in the amount of any cash on the balance sheet (subject to certain exceptions) in excess of $25 million.

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, as applicable, 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, 2020, we were in compliance with all of the covenants under the Credit Facility and the Second Lien Facility.

Results of Operations

Presentation of Financial Information and Changes in Accounting Principles

Adoption of New Accounting Standards

As discussed in further detail in Notes 2, 5 and 11 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data," we have adopted two accounting standards that impact the comparability of our financial statements: Financial Accounting Standards Board's, or FASB, Accounting Standards Update, or ASU, *Measurement of Credit Losses on Financial Instruments*, or ASU 2016–13, effective January 1, 2020 and ASC Topic 842,*Leases*, or ASC Topic 842, effective January 1, 2019. We adopted ASU 2016–13 utilizing the optional cumulative effect transition approach. As a result of the adoption of ASU 2016–13, certain amounts included in the caption *Other revenues, net* are not comparable between the 2020 and 2019 presentations; however, we do not believe that such differences are material. The adoption of ASC Topic 842 impacts the presentation and comparability of (i) Lease operating, or LOE, expense and (ii) General and administrative, or G&A, expenses. We adopted ASC Topic 842 utilizing the cumulative effect transition method effective January 1, 2019. Accordingly, our LOE and G&A expenses for the years ended December 31, 2020 and 2019 are not comparable to the 2018 presentation of these items. Our discussion and analysis of these items in the *Results of Operations* that follow address the effects of changes directly attributable to the adoption of ASU 2016–13 and ASC Topic 842.

Sales Volume

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

	Total Sales Volume [1]		
	Year Ended December 31,		
	2020	2019	2018
Crude oil (MBbl)	6,829	7,453	6,077
NGLs (MBbl)	1,165	1,491	1,004
Natural gas (MMcf)	5,360	7,067	5,181
Total (MBOE)	8,887	10,121	7,944
Year-over-year variances (MBOE)		(1,234)	2,177
% Changes		(12) %	27 %

	Average Daily Sales Volume [1]		
	Year Ended December 31,		
	2020	2019	2018
Crude oil (Bbl per day)	18,658	20,418	16,650
NGLs (Bbl per day)	3,182	4,085	2,750
Natural gas (MMcf per day)	15	19	14
Total (BOEPD)	24,281	27,730	21,765
Year-over-year variances (MBOE)		(3,449)	5,965
% Changes		(12) %	27 %

	Total Sales Volume by Region [1]		
	Year Ended December 31,		
	2020	2019	2018
South Texas	8,887	10,121	7,780
Mid-Continent [2]	—	—	165
Total (MBOE)	8,887	10,121	7,944
Year-over-year variances (MBOE)		(1,234)	2,177
% Changes		(12) %	27 %

	Average Daily Sales Volume by Region [1]		
	Year Ended December 31,		
	2020	2019	2018
South Texas	24,281	27,730	21,314
Mid-Continent [2]	—	—	451
Total (BOEPD)	24,281	27,730	21,765
Year-over-year variances (MBOE)		(3,449)	5,965
% Changes		(12) %	27 %

[1] All volumetric statistics presented represent volumes of commodity production that were actually sold during the year ended December 31, 2020 as presented. Volumes of crude oil physically produced in excess of volumes sold are placed in temporary storage to be sold in subsequent periods.

[2] Mid-Continent operations were sold on July 31, 2018.

2020 vs. 2019. Total sales volume decreased 12 percent during 2020 compared to 2019 due primarily to fewer wells turned to sales in 2020 primarily as a result of the temporary suspension of our 2020 drilling program shortly after the magnitude of the global economic downturn associated with COVID-19 pandemic became evident. While overall sales volume was lower in 2020, crude oil sales volume decreased by only eight percent compared to 2019 due to a shift in development focus that began in the second half of 2019 to the oilier north and eastern portions of our acreage holdings. While both years experienced natural production declines, the effect in 2020 was more significant with the completion of fewer new wells in 2020.

Prior to the temporary suspension in April, we operated three drilling rigs and resumed drilling with one rig beginning in October 2020 and with a second rig in mid-November 2020. This compared to up to three rigs operating consistently during the majority of 2019. During 2020, we turned 23 gross (20.6 net) wells to sales compared to 48 gross (43.3 net) wells during 2019.

Approximately 77 percent of total sales volume during 2020 was attributable to crude oil compared to approximately 74 percent during 2019. The increase in the crude oil composition of total sales volume was due primarily to the aforementioned shift in development plans that began in the second half of 2019 with less emphasis in the southeastern portion of our acreage holdings which have historically higher gas content.

2019 vs. 2018. Total sales volume increased 27 percent during 2019 compared to 2018 due primarily to a greater number of higher working interest wells turned to sales in the fourth quarter of 2018 through December 31, 2019 when compared to the corresponding periods from the fourth quarter of 2017 through December 31, 2018 as well as the effect of a full year of production from the Hunt Acquisition. These increases were partially offset by the effect of the divestiture in July 2018 of our former Mid-Continent operations, as well as natural production declines from our more mature Eagle Ford wells.

We operated two drilling rigs during the majority of 2019 compared to three during the majority of 2018. During 2019, we turned 48 gross (43.3 net) wells to sales compared to 53 gross (45.5 net) wells during 2018. When considering the wells turned to sales in the fourth quarters of the prior years for which we would receive a full year of subsequent production, we had 58 gross (52.2 net) wells for the year ended December 31, 2019 as compared to 62 gross (50.8 net) wells for the year ended December 31, 2018.

Approximately 74 percent of total sales volume during 2019 was attributable to crude oil when compared to approximately 76 percent during 2018. The decline in the crude oil composition of total sales volume was due primarily to a higher gas content experienced with certain wells, primarily in the southeastern portion of our acreage holdings.

Product Revenues and Prices

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

	Total Product Revenues		
	Year Ended December 31,		
	2020	2019	2018
Crude oil	$ 251,741	$ 434,713	$ 402,485
NGLs	8,948	16,589	21,073
Natural gas	10,103	17,733	15,972
Total	$ 270,792	$ 469,035	$ 439,530
Year-over-year variances		$ (198,243)	$ 29,505
% Changes		(42)%	7 %

	Product Revenues per Unit of Volume		
	Year Ended December 31,		
	2020	2019	2018
Crude oil ($ per barrel)	$ 36.86	$ 58.33	$ 66.23
NGLs ($ per barrel)	$ 7.68	$ 11.13	$ 20.99
Natural gas ($ per Mcf)	$ 1.88	$ 2.51	$ 3.08
Total ($ per BOE)	$ 30.47	$ 46.34	$ 55.33
Year-over-year variances		$ (15.87)	$ (8.99)
% Changes		(34)%	(16)%

	Product Revenues by Region		
	Year Ended December 31,		
	2019	2018	2017
South Texas	$ 270,792	$ 469,035	$ 435,599
Divested properties [1]	—	—	3,931
Total	$ 270,792	$ 469,035	$ 439,530
Year-over-year variances		$ (198,243)	$ 29,505
% Changes		(42)%	7 %

	Product Revenues per BOE by Region		
	Year Ended December 31,		
	2019	2018	2017
South Texas	$ 30.47	$ 46.34	$ 55.99
Divested properties [1]	$ —	$ —	$ 23.87
Total ($ per BOE)	$ 30.47	$ 46.34	$ 55.33
Year-over-year variances		$ (15.87)	$ (8.99)
% Changes		(34)%	(16)%

[1] Mid-Continent operations were sold on July 31, 2018.

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

	Year Ended December 31, 2020 vs. Year Ended December 31, 2019			Year Ended December 31, 2019 vs. Year Ended December 31, 2018		
	Revenue Variance Due to			Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ (36,390)	$ (146,582)	$ (182,972)	$ 91,108	$ (58,880)	$ 32,228
NGLs	(3,630)	(4,011)	(7,641)	10,227	(14,711)	(4,484)
Natural gas	(4,282)	(3,348)	(7,630)	5,815	(4,054)	1,761
	$ (44,302)	$ (153,941)	$ (198,243)	$ 107,150	$ (77,645)	$ 29,505

2020 vs. 2019. Our product revenues decreased during 2020 compared to 2019 due primarily to 37 percent lower crude oil prices and eight percent lower volume, respectively. NGL revenues declined in 2020 due to 31 percent lower prices and 22 percent lower volume. Lower natural gas revenues were attributable to 25 percent lower pricing and 24 percent lower volume in 2020. Total crude oil revenues were approximately 93 percent of our total product revenues during each of the years ended December 31, 2020 and 2019.

2019 vs. 2018. Our product revenues increased seven percent during 2019 over 2018 due primarily to approximately 23 percent higher crude oil volumes partially offset by 12 percent lower crude oil pricing resulting in higher overall product revenues. NGL revenues declined approximately 21 percent in 2019 due to substantially lower pricing (47 percent) partially offset by approximately 49 percent higher volumes. Natural gas revenues increased approximately 11 percent due primarily to approximately 36 percent higher volumes substantially offset by approximately 19 percent lower pricing. Crude oil revenues were approximately 93 percent of our total revenues during 2019 as compared to approximately 92 percent during 2018.

Realized Differentials

The following table reconciles our realized price differentials from weighted-average NYMEX-quoted prices for WTI crude oil for the periods presented:

	Year Ended December 31,		
	2020	2019	2018
Realized crude oil prices per barrel	$ 36.86	$ 58.33	$ 66.23
Weighted-average WTI prices	39.46	57.04	65.56
Realized differential to WTI per barrel	$ (2.60)	$ 1.29	$ 0.67

The adverse impact of COVID-19 and instability in the global energy markets exacerbated a declining trend in realized prices that effectively eliminated a premium margin to the NYMEX WTI index price for crude oil in 2020 compared to 2019. Historically, we had realized premiums to NYMEX WTI index pricing as a substantial portion of our crude oil volume was sold based on Light Louisiana Sweet, or LLS, or Magellan East Houston, or MEH, pricing. During 2020, we did not have any crude oil sales based on the LLS index.

Effects of Derivatives

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

	Year Ended December 31,		
	2020	2019	2018
Crude oil revenues as reported	$ 251,741	$ 434,713	$ 402,485
Realized derivative settlements, net	93,462	(10,501)	42,447
	$ 345,203	$ 424,212	$ 444,932
Crude oil prices per Bbl, as reported	$ 36.86	$ 58.33	$ 66.23
Realized derivative settlements per Bbl	13.69	(1.41)	6.98
	$ 50.55	$ 56.92	$ 73.21
Natural gas revenues, as reported	$ 10,103	$ 17,733	$ 15,972
Realized derivative settlements, net	(32)	—	—
	$ 10,071	$ 17,733	$ 15,972
Natural gas prices per Mcf	$ 1.88	$ 2.51	$ 3.08
Realized derivative settlements per Mcf	—	—	—
	$ 1.88	$ 2.51	$ 3.08

Gain (Loss) on Sales of Assets

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

	Year Ended December 31,		
	2020	2019	2018
Gain (loss) on sales of assets, net	$ 18	$ 5	$ (177)

2020, 2019 and 2018. In 2020, 2019 and 2018, we recognized insignificant net gains and losses attributable to the sale or trade of certain support equipment and surplus and scrap tubular inventory and well materials.

Other Revenues, Net

Other revenues, net, includes fees for marketing and water disposal services that we charge to third parties, net of related expenses, as well as other miscellaneous revenues and credits attributable to our current operations. In addition, charges attributable to credit losses associated with our trade and joint venture partner receivables are included in this caption as a contra-revenue item.

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

	Year Ended December 31,		
	2020	2019	2018
Other revenues, net	$ 2,458	$ 2,176	$ 1,479

2020 vs. 2019. Other revenues, net increased during 2020 from 2019 due primarily to higher water disposal revenues, net of related expenses. The higher water disposal-related net revenues during 2020 is due primarily to $0.8 million of certain unscheduled workover repairs and maintenance costs incurred during the second quarter of 2019 at our water disposal facilities. The overall increase in other revenues, net was partially offset by a decline in marketing fees in 2020 due primarily to lower overall sales volume, commodity prices and related marketing activities. Furthermore, the 2020 period includes credit loss charges of $0.1 million determined in accordance with ASU 2016–13 that are substantially greater in amount and were not comparable to similar charges incurred in 2019 under prior GAAP.

2019 vs. 2018. Other revenues, net increased during 2019 from 2018 due primarily to higher water disposal revenues attributable to higher production partially offset by the aforementioned unscheduled repairs and maintenance costs incurred during the second quarter of 2019 at our water disposal facilities.

Lease Operating Expenses

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

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

	Year Ended December 31,		
	2020	2019	2018
Lease operating	$ 37,463	$ 43,088	$ 35,879
Per unit ($/BOE)	$ 4.22	$ 4.26	$ 4.52

2020 vs. 2019. LOE decreased on an absolute and per unit basis during 2020 when compared to 2019. The absolute decrease was due primarily to lower sales volume in 2020 primarily resulting in lower overall variable costs including compression, chemicals, labor, utilities as well as substantially lower repairs and maintenance costs. Despite the decrease in sales volume, our per unit rates experienced a marginal decrease as our fixed cost burden has declined from 2019. In addition, we experienced an overall higher level of efficiency attributable to a combination of cost-containment efforts and the application of operational improvements. These broad reductions were partially offset by higher water disposal costs associated with protective measures from offset stimulation activities during 2020.

2019 vs. 2018. LOE increased on an absolute basis, but declined on a per unit basis during 2019 when compared to 2018 due primarily to the overall effect of 27 percent higher production volume during 2019. The volume-based absolute increases were primarily attributable to compression and gas lift, water disposal, utilities and environmental costs for a combined effect of $5.6 million. Higher maintenance costs of $1.3 million were incurred in 2019. In addition, 2019 includes the effects of two additional months of production attributable to the Hunt Acquisition.

Gathering Processing and Transportation

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

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

	Year Ended December 31,		
	2020	2019	2018
Gathering, processing and transportation	$ 22,050	$ 23,197	$ 18,626
Per unit ($/BOE)	$ 2.48	$ 2.29	$ 2.34

2020 vs. 2019. While GPT expense declined on an absolute basis during 2020 as compared to 2019 due primarily to lower sales volumes, we did experience an increase on a per unit basis during 2020 due primarily to a scheduled rate increase that became effective August 1, 2019, for crude oil gathering services. Accordingly, the higher rates for gathering services were in effect for the entirety of 2020 as compared to only five months during 2019. The absolute decline in GPT expense was partially offset by short-term rental charges that we incurred in 2020 to temporarily store a portion of our crude oil production as well as a shift in the mix of crude oil production sold at a central delivery point and pipeline from that sold at the wellhead which incurs no corresponding GPT expense subsequent to the achievement of required minimum crude oil volumes transported by pipeline.

2019 vs. 2018. GPT expense increased on an absolute basis during 2019 when compared to 2018 due primarily to substantially higher production volumes. Per unit costs declined marginally in 2019 compared to 2018 due primarily to a shift in the mix of crude oil production sold at the wellhead with no corresponding GPT expense partially offset by a scheduled rate increase effective August 1, 2019 discussed above.

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 assessed 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:

	Year Ended December 31,		
	2020	2019	2018
Production and ad valorem taxes			
Production/severance taxes	$ 11,695	$ 21,774	$ 20,619
Ad valorem taxes	4,924	6,283	2,928
	$ 16,619	$ 28,057	$ 23,547
Per unit ($/BOE)	$ 1.87	$ 2.77	$ 2.96
Production/severance tax rate as a percent of product revenues	4.3 %	4.6 %	4.7 %

2020 vs. 2019. Production taxes decreased on an absolute basis and per unit basis during 2020 when compared to 2019 due primarily to decreases in aggregate commodity sales prices of 34 percent in 2020. In addition, we were able to reclassify certain wells with regulatory certification from crude oil to high cost gas which has resulted in severance tax savings in the second half of 2020. Beginning in the second quarter of 2020, we decreased the accruals for ad valorem taxes based on our most recent estimates for assessments which reflects the recent substantial decline in commodity prices. During the second half of 2019, we increased our ad valorem accruals due to higher commodity-price based valuation assessments experienced in the 2018 and 2019 annual assessment periods, which were reflective of indicative prices published for 2019, and the effects of growing our assessable property base and increased working interests from acquisition activity.

2019 vs. 2018. Production taxes increased on an absolute basis, but declined on a per unit basis during 2019 when compared to 2018 due primarily to increased production volume despite lower overall commodity sales prices. Accruals for ad valorem taxes also increased substantially for the 2019 periods due to a higher commodity-price based valuation assumption and the effects of growing our assessable property base and increased working interests from acquisition activity.

General and Administrative

Our G&A expenses include employee compensation, benefits and other related costs for our corporate management and governance functions, rent and occupancy costs for our corporate facilities, insurance, and professional fees and consulting costs supporting various corporate-level functions, among others. In order to facilitate a meaningful discussion and analysis of our results of operations with respect to G&A expenses, 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:

	Year Ended December 31,		
	2020	2019	2018
Primary G&A	$ 24,086	$ 20,602	$ 17,236
Share-based compensation	3,284	4,082	4,618
Significant special charges:			
Organizational restructuring, including severance	1,446	—	—
Acquisition, divestiture and strategic transaction costs	4,973	800	3,960
Executive retirement costs	—	—	250
Total general and administrative expenses	$ 33,789	$ 25,484	$ 26,064
Per unit ($/BOE)	$ 3.80	$ 2.52	$ 3.28
Per unit excluding all share-based compensation and significant special charges identified above ($/BOE)	$ 2.71	$ 2.04	$ 2.17

2020 vs. 2019. Our primary G&A expenses increased on an absolute and per unit basis during 2020 compared to 2019. The absolute increase is due primarily to a lower level of capitalized labor attributable to the suspension of our drilling program from April through October 2020. In addition, we incurred higher information technology support, occupancy and consulting costs and professional fees in 2020. These increases were partially offset by lower incentive compensation accruals and the absence of cost-of-living and similar adjustments to salaries and wages in 2020. The increase in per unit costs was exacerbated by the effect of lower overall production volume during 2020.

Share-based compensation charges during the periods presented are attributable to the amortization of compensation cost, net of forfeitures, associated with the grants of time-vested restricted stock units, or RSUs, and performance-based restricted stock units, or PRSUs. The grants of RSUs and PRSUs are described in greater detail in Note 16 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." A substantial portion of the share-based compensation expense is attributable to the RSU and PRSU grants made in the normal course in March of 2020 and January of 2017. The remainder is attributable to grants of RSUs and PRSUs to certain employees upon their hiring or as a result of promotion during the periods presented. All of our share-based compensation represents non-cash expenses.

In connection with the appointment of our new CEO and the related executive transition, we incurred certain incremental G&A costs. In July 2020, we also initiated a limited reduction-in-force, or RIF, action resulting in the payment of employee termination and severance benefits. Collectively, we have characterized these costs broadly as an organizational restructuring for which we incurred approximately $1.4 million of costs.

Beginning in the third quarter of 2020 and through the end of the year, we incurred certain professional fees and consulting costs of approximately $5.0 million in connection with the Juniper Transaction as described in greater detail in Note 2 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data.". During the first half of 2019, we incurred consulting and other costs, including legal and other professional fees, primarily associated with a merger transaction which was mutually terminated by us and the counterparty in March 2019.

2019 vs. 2018. Our primary G&A expenses increased on an absolute basis and decreased on a per unit basis during 2019 compared to 2018. The absolute increases are due primarily to the effects of higher payroll, benefits and support costs attributable to a higher overall employee headcount. In addition, we incurred higher occupancy costs and higher consulting and related costs including those associated with a senior management transition in the second half of 2019. Higher production volume had the effect of reducing G&A per unit of production during 2019.

We incurred consulting and other costs in the second half of 2018 which continued into the first quarter of 2019 associated with the previously terminated merger transaction. In addition to these costs, we incurred transaction costs in 2018 associated with the Mid-Continent divestiture and the Hunt Acquisition, including legal, due diligence and other professional fees. We also paid certain costs attributable to the retirement of our former Executive Chairman in February 2018.

Depreciation, Depletion and Amortization (DD&A)

DD&A expense includes charges for the allocation of property costs based on the volume of production, depreciation of fixed assets other than oil and gas assets as well as the accretion of our ARO liabilities. The following table sets forth total and per unit costs for DD&A for the periods presented:

	Year Ended December 31,		
	2020	**2019**	**2018**
DD&A expense	$ 140,673	$ 174,569	$ 127,961
DD&A rate ($/BOE)	$ 15.83	$ 17.25	$ 16.11

2020 vs. 2019. DD&A decreased on an absolute and a per unit basis during 2020 when compared to 2019. Lower production volume provided for decreases of approximately $21.3 million while $12.6 million was attributable to the lower DD&A rates in 2020. The lower DD&A rate in 2020 was primarily attributable to the effect of adding additional reserves in the fourth quarter of 2019 and the impairments recorded in 2020 as referenced and discussed further below.

2019 vs. 2018. DD&A increased on an absolute and per unit basis during 2019 when compared to 2018. Higher production volume provided for an increase of approximately $35.1 million while $11.5 million was attributable to the higher DD&A rates in 2019. The higher DD&A rates in 2019 are attributable to higher finding and development costs per unit of reserves added to the full cost pool.

Impairment of Oil and Gas Properties

We assess our oil and gas properties on a quarterly basis based on the results of a Ceiling Test in accordance with the full cost method of accounting for oil and gas properties.

	Year Ended December 31,		
	2020	**2019**	**2018**
Impairment of oil and gas properties	$ 391,849	$ —	$ —

2020. During 2020 we recorded impairments of our oil and gas properties as a result of a decline in the twelve-month average prices of crude oil, NGLs and natural gas as indicated by our Ceiling Test under the full cost method of accounting for oil and gas properties. While current commodity prices have recovered somewhat, it is nonetheless possible that we will experience an additional impairment in the carrying value of our oil and gas properties during the first quarter of 2021.

Interest Expense

Interest expense includes charges for outstanding borrowings under the Credit Facility and the Second Lien Facility, derived from internationally-recognized interest rates with a premium based on our credit profile and the level of credit outstanding. In addition, we are assessed certain fees for the overall credit commitments provided to us as well as fees for credit utilization and letters of credit. Also included is the accretion of original issue discount on the Second Lien Facility and the amortization of issuance costs capitalized attributable to the Credit Facility and the Second Lien Facility. These costs are partially offset by interest amounts that we capitalize on unproved property costs while we are engaged in the evaluation of projects for the underlying acreage.

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

	Year Ended December 31,		
	2020	2019	2018
Interest on borrowings and related fees	$ 29,851	36,593	$ 32,164
Accretion of original issue discount	811	743	680
Amortization of debt issuance costs	3,339	2,611	2,736
Capitalized interest	(2,744)	(4,136)	(9,118)
	$ 31,257	$ 35,811	$ 26,462

2020 vs. 2019. Interest expense decreased during 2020 as compared to 2019 due primarily to the effect of lower interest rates partially offset by higher outstanding balances under the Credit Facility during 2020. The weighted-average balances under the Credit Facility were higher in 2020 compared to 2019 period by approximately $4 million. The weighted-average interest rates were lower during the same period by 124 basis points. The accretion of original issue discount, or OID, is entirely attributable to the Second Lien Facility and the amortization of debt issuance costs includes amounts attributable to both the Credit Facility and Second Lien Facility. We wrote off approximately $1 million of debt issuance costs associated with the Credit Facility in the first half of 2020 commensurate with the reduction in the borrowing base. We capitalized a smaller portion of interest during 2020 as we maintained a smaller portion of unproved property as compared to 2019.

2019 vs. 2018. Interest expense increased during 2019 as compared to 2018 due primarily to higher outstanding balances under the Credit Facility partially offset by the effect of lower interest rates. Weighted-average balances under the Credit Facility were higher in 2019 compared to 2018 by approximately $119 million while the weighted-average interest rates were lower during the same period by 97 basis points. The accretion of OID is entirely attributable to the Second Lien Facility and the amortization of debt issuance costs includes amounts attributable to both the Credit Facility and Second Lien Facility. We capitalized a smaller portion of interest during 2019 as we maintained a substantially smaller portion of unproved property as compared to 2018.

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 and variable interest rates.

The following table summarizes the gains and (losses) attributable to our commodity derivatives portfolio and interest rate swaps for the periods presented:

	Year Ended December 31,		
	2020	2019	2018
Commodity derivative gains (losses)	$ 95,932	$ (68,131)	$ 37,427
Interest rate swap gains (losses)	$ (7,510)	$ —	$ —
	$ 88,422	$ (68,131)	$ 37,427

2020 vs. 2019. In 2020, commodity prices collapsed dramatically compared to 2019 due primarily to the economic slowdown associated with the COVID-19 pandemic and the disruptions in the global energy markets. Accordingly, we substantially expanded our commodity hedging program and actively added hedge contracts that allowed us to benefit from falling prices primarily in the first half of 2020. A substantial portion of our net commodity derivative gains in 2020 were realized and were supplemented to a lesser extent by net mark-to-market gains attributable to open positions. By contrast, we had substantial net unrealized mark-to-market losses in 2019 as crude oil prices increased by year-end 2019 relative to our hedged positions. Realized settlements receipts for crude oil and natural gas derivatives were $93.4 million during 2020 as compared to the realized settlement payments for crude oil of $10.5 million in 2019.

In 2020, we began hedging a portion of our exposure to variable interest rates associated with our Credit Facility and Second Lien Facility. During 2020, we paid $2.2 million of net settlements from our interest rate swaps as the benchmark rate declined relative to our weighted-average hedged rate and we recognized mark-to-market losses as well.

2019 vs. 2018. In 2019, the forward curve for crude oil prices increased relative to our weighted-average hedged prices resulting in net losses for our crude oil derivative portfolio. We paid net cash settlements of $4.1 million and $48.3 million in 2019 and 2018, respectively.

Other, Net

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

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

	Year Ended December 31,		
	2020	2019	2018
Other, net	$ (850)	$ (153)	$ 2,266

2020. Other, net income (expense) decreased during 2020 as compared to 2019 due primarily to certain costs that were incurred in 2020 that were attributable to previously divested properties that were otherwise not recoverable from the buyers of those properties.

2019. Other, net income (expense) decreased during 2019 as compared to 2018 due primarily to the write-off in 2019 of $0.2 million attributable to acquisition transactions in prior years that were no longer deemed recoverable. This charge was partially offset in 2019 by recoveries of sales and use taxes attributable to previously divested properties.

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

Reorganization Items, Net

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

	Year Ended December 31,		
	2020	2019	2018
Legal and professional fees and expenses	$ —	$ —	$ 200
Other reorganization items	—	—	3,122
	$ —	$ —	$ 3,322

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

Income Taxes

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

	Year Ended December 31,		
	2020	2019	2018
Income tax (expense) benefit	$ 2,303	$ (2,137)	$ (523)
Effective tax rate	0.7 %	3.0 %	0.2 %

2020. The provision for the year ended December 31, 2020 includes current federal benefits of $1.2 million attributable to refundable alternative minimum tax, or AMT, credits for the 2020 tax year, which when combined with the amounts attributable to 2019 that had been recognized on our Consolidated Balance Sheet as of December 31, 2019 as a current asset, were received in 2020 as an acceleration of all AMT credits in connection with certain provisions of the CARES Act. This AMT benefit was offset by a corresponding decrease in the deferred tax asset associated with AMT credit carryforwards giving rise to deferred federal expense for the year ended December 31, 2020. In addition, we have recognized a deferred state tax expense of $2.7 million attributable to property and equipment and $0.4 million of current state expense attributable to the Texas margin tax for the year ended December 31, 2020 for an overall effective tax rate of 0.7%.

2019. The provision for the year ended December 31, 2019 includes current federal benefits of $1.2 million attributable to the anticipated refund of AMT credits for the 2019 tax year. The amount for 2019 was recognized on our Consolidated Balance Sheet as of December 31, 2019 as a current asset. These benefits have been offset by corresponding decreases in the deferred tax asset associated with AMT credit carryforwards giving rise to deferred federal expense for the year ended December 31, 2019. In addition, we have recognized a deferred state tax expense of $2.1 million attributable to property and equipment for an overall effective tax rate of 3.0%.

2018. The provision for the year ended December 31, 2018 includes a current federal benefit of $2.5 million attributable to the anticipated refund of AMT credits for the 2018 tax year. The $2.5 million attributable to 2018 was refunded to us in 2019. This benefit is offset by a corresponding decrease in the deferred tax asset associated with the refundable AMT credit giving rise to a deferred federal expense. In addition, we have recognized a deferred state tax expense of $0.5 million for an overall effective tax rate of 0.2%.

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, 2020, the material off-balance sheet arrangements and transactions that we have entered into included information technology licensing, service agreements and letters of credit, all of which are customary in our business. See "*Contractual Obligations*" summarized below and Note 14 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, 2020:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Credit Facility [1]	$ 314,400	$ —	$ —	$ 314,400	$ —
Second Lien Facility [2]	200,000	—	200,000	—	—
Interest payments on long-term debt [3]	63,564	26,692	33,152	3,720	—
Operating leases [4]	2,828	936	1,746	146	—
Crude oil gathering and transportation commitments [5]	89,636	12,962	25,924	25,924	24,826
Asset retirement obligations [6]	118,311	—	—	—	118,311
Derivatives	9,619	6,742	2,877	—	—
Other commitments [7]	501	317	184	—	—
Total contractual obligations	$ 798,859	$ 47,649	$ 263,883	$ 344,190	$ 143,137

[1] Assumes that the amount outstanding of $314.4 million as of December 31, 2020 will remain outstanding until its maturity in 2024. 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 9 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, 2020 will remain outstanding until its original maturity in 2022 (without giving effect to the extension of its maturity in connection with Second Lien Amendment that became effective in January 2021). The Second Lien Facility has been classified as a long term liability on our Consolidated Balance Sheet as described in "Financial Condition – Liquidity" and in Note 9 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[3] Represents estimated interest payments that will be due under the Credit Facility and Second Lien Facility, assuming that the underlying LIBOR-based interest rates in effect at December 31, 2020 remain in effect and the amounts outstanding of $314.4 million and $200 million as of December 31, 2020, respectively, will remain outstanding until their maturities in 2024 and 2022, respectively.

[4] Relates primarily to office facilities and equipment leases as described in Note 11 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[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 Nuevo Dos Marketing, LLC.

[6] Represents the undiscounted balance payable, primarily for the plugging of inactive wells, in periods more than five years in the future for which $5.5 million, on a discounted basis, has been recognized on our Consolidated Balance Sheet as of December 31, 2020 and illustrated in Note 8 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." 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.

[7] Represents all other significant obligations including information technology licensing and service agreements, among others as described in Note 14 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

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.

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

We apply 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 after-tax discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes, or a Ceiling Test. The estimated after-tax 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, 2020, the carrying value of our proved oil and gas properties exceeded the limit determined by the Ceiling Test by $120.3 million which resulted in our recording an impairment charge for the three months then ended and a total of $391.8 million for the year ended December 31, 2020. Because the Ceiling Test utilizes commodity prices based on a trailing twelve month average, it does not fully reflect the substantial decline in commodity prices that accelerated early in the second quarter of 2020 due to the economic impact of the COVID-19 pandemic and the ongoing disruption in global energy markets. While current commodity prices have recovered somewhat, it is nonetheless possible that we will experience an additional impairment in the carrying value of our oil and gas properties during the first quarter of 2021.

Derivative Activities

We utilize derivative instruments, typically swaps, put options and call options which are placed with financial institutions that we believe are acceptable credit risks, to mitigate our financial exposure to commodity price volatility associated with anticipated sales of our future production and volatility in interest rates attributable to our variable rate debt instruments. All derivative instruments are recognized in our Consolidated Financial Statements at fair value with the changes recorded currently in earnings. We determine the fair values of our commodity derivative instruments using industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied volatilities, time value and non-performance risk. 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 expected 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, 2020, we believe it is more likely than not that we will not have sufficient future taxable income to realize the benefit of our gross deferred tax assets and, accordingly, have maintained a full valuation allowance.

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, 2020, we had borrowings of $314.4 million under the Credit Facility at an interest rate of 3.40%. As of December 31, 2020, we had borrowings of $195.1 million under the Second Lien Facility, net of OID and issuance costs, at an interest rate of 8.00%. Assuming a constant borrowing level under the Credit and Second Lien Facilities, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in interest expense of approximately $5.1 million on an annual basis, excluding the offsetting impact of our interest rate swap derivatives.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars and swaps) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of oil and natural gas. As of December 31, 2020, we were not utilizing any derivative instruments with respect to NGLs, although we may do so in the future.

As of December 31, 2020, we reported net commodity derivative liabilities of $4.3 million. The contracts associated with this position are with eight counterparties, all of which are investment grade financial institutions. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

During the year ended December 31, 2020, we reported net commodity derivative gains of $95.9 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 6 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 commodity price risk management activities.

The following table sets forth our commodity derivative positions as of December 31, 2020:

	1Q2021	2Q2021	3Q2021	4Q2021	1Q2022	2Q2022	3Q2022	4Q2022	1Q2023	2Q2023
NYMEX WTI Crude Swaps										
Average Volume Per Day (barrels)	3,889	3,297	815	815						
Weighted Average Swap Price ($/barrel)	$ 54.38	$ 55.89	$ 45.54	$ 45.54						
NYMEX WTI Crude Collars										
Average Volume Per Day (barrels)	9,722	10,440	9,239	8,152	2,917	2,885	2,853	2,853	2,917	2,855
Weighted Average Purchased Put Price ($/barrel)	$ 40.00	$ 42.84	$ 40.35	$ 40.40	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Weighted Average Sold Call ($/barrel)	$ 45.78	$ 51.70	$ 51.85	$ 52.10	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00
NYMEX WTI Purchased Puts										
Average Volume Per Day (barrels)	1,667									
Weighted Average Purchased Put Price ($/barrel)	$ 55.00									
NYMEX WTI Sold Puts										
Average Volume Per Day (barrels)	556	11,538	5,707	5,707						
Weighted Average Sold Put ($/barrel)	$ 26.50	$ 36.93	$ 35.14	$ 35.14						
MEH-NYMEX WTI Crude Basis Swaps										
Average Volume Per Day (barrels)	8,889									
Weighted Average Swap Price ($/barrel)	$ 1.16									
NYMEX WTI Crude CMA Roll Basis Swaps										
Average Volume Per Day (barrels)	14,444	13,187	13,043	13,043						
Weighted Average Swap Price ($/barrel)	$ (0.18)	$ 0.07	$ 0.07	$ 0.07						
NYMEX HH Collars										
Average Volume Per Day (MMBtus)	10,000	9,890	9,783	9,783						
Weighted Average Purchased Put Price ($/MMBtu)	$ 2.607	$ 2.607	$ 2.607	$ 2.607						
Weighted Average Sold Call ($/MMBtu)	$ 3.117	$ 3.117	$ 3.117	$ 3.117						
NYMEX HH Sold Puts										
Average Volume Per Day (MMBtus)	6,667	6,593	6,522	6,522						
Weighted Average Sold Put Strike ($/MMBtu)	$ 2.000	$ 2.000	$ 2.000	$ 2.000						

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

	Change of 10% per Barrel of Crude Oil ($ in millions)	
	Increase	**Decrease**
Effect on the fair value of crude oil derivatives [1]	$ (23.3)	$ 18.6
Effect on 2021 operating income, excluding crude oil derivatives [2]	$ 30.1	$ (30.1)

[1] Based on derivatives outstanding as of December 31, 2020.

[2] Based on our 2021 Business Plan consistent with the assumptions used to determine our proved reserves as disclosed in Item 2, "Properties – *Summary of Oil and Gas Reserves* ." These sensitivities are subject to significant change

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, 2020 and 2019, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 9, 2021 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 regarding 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.

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Depletion expense and impairment of oil and gas properties impacted by the Company's estimation of proved reserves

As described further in Note 3 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future net revenues to record depletion expense and assess its oil and gas properties for potential impairment. To estimate the volume of proved reserves and future net revenue, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected with reasonable certainty to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and impairment assessment and measurement. We identified the estimation of proved reserves of oil and gas properties as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future net revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense and potential impairment. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the design and operating effectiveness of controls relating to management's estimation of proved reserves for the purpose of estimating depletion expense and assessing and measuring the Company's oil and gas properties for potential impairment.
- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's specialists.
- To the extent key inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, including, but not limited to: historical pricing differentials, operating costs, estimated capital costs, and ownership interests, we tested management's process for determining the assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by performing the following:
  - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
  - Evaluated models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs;
  - Evaluated the method used to determine the future capital costs and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells;
  - Tested the working and net revenue interests used in the reserve report by inspecting land and division order records;
  - Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties; and
  - Applied analytical procedures to the reserve report forecasted production by comparing to historical actual results, and to the prior year reserve report.

/s/ GRANT THORNTON LLP

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

Houston, Texas
March 9, 2021

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, 2020, 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, 2020, 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, 2020, and our report dated March 9, 2021 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 9, 2021

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

	Year Ended December 31,		
	2020	**2019**	**2018**
Revenues			
Crude oil	$ 251,741	$ 434,713	$ 402,485
Natural gas liquids	8,948	16,589	21,073
Natural gas	10,103	17,733	15,972
Gain (loss) on sales of assets, net	18	5	(177)
Other revenues, net	2,458	2,176	1,479
Total revenues	273,268	471,216	440,832
Operating expenses			
Lease operating	37,463	43,088	35,879
Gathering, processing and transportation	22,050	23,197	18,626
Production and ad valorem taxes	16,619	28,057	23,547
General and administrative	33,789	25,484	26,064
Depreciation, depletion and amortization	140,673	174,569	127,961
Impairments of oil and gas properties	391,849	—	—
Total operating expenses	642,443	294,395	232,077
Operating income (loss)	(369,175)	176,821	208,755
Other income (expense)			
Interest expense, net of amounts capitalized	(31,257)	(35,811)	(26,462)
Derivatives	88,422	(68,131)	37,427
Other, net	(850)	(153)	2,266
Reorganization items, net	—	—	3,322
Income (loss) before income taxes	(312,860)	72,726	225,308
Income tax (expense) benefit	2,303	(2,137)	(523)
Net income (loss)	$ (310,557)	$ 70,589	$ 224,785
Net income (loss) per share:			
Basic	$ (20.46)	$ 4.67	$ 14.93
Diluted	$ (20.46)	$ 4.67	$ 14.70
Weighted average shares outstanding – basic	15,176	15,110	15,059
Weighted average shares outstanding – diluted	15,176	15,126	15,292

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2020	**2019**	**2018**
Net income (loss)	$ (310,557)	$ 70,589	$ 224,785
Other comprehensive income (loss):			
Change in pension and postretirement obligations, net of tax	(72)	(141)	82
	(72)	(141)	82
Comprehensive income (loss)	$ (310,629)	$ 70,448	$ 224,867

See accompanying notes to consolidated financial statements.

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

	December 31,	
	2020	**2019**
Assets		
Current assets		
Cash and cash equivalents	$ 13,020	$ 7,798
Accounts receivable, net of allowance for credit losses	42,562	70,716
Derivative assets	78,793	4,131
Income taxes receivable	—	1,236
Prepaid and other current assets	19,045	4,458
Total current assets	153,420	88,339
Property and equipment, net (full cost method)	723,549	1,120,425
Derivative assets	25,449	2,750
Other assets	4,908	6,724
Total assets	$ 907,326	$ 1,218,238
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 62,768	$ 105,824
Derivative liabilities	85,427	23,450
Total current liabilities	148,195	129,274
Other liabilities	8,362	8,382
Deferred income taxes	—	1,424
Derivative liabilities	28,434	3,385
Long-term debt, net	509,497	555,028
Commitments and contingencies (Note 14)		
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; 15,200,435 and 15,135,598 shares issued as of December 31, 2020 and 2019, respectively	152	151
Paid-in capital	203,463	200,666
Retained earnings	9,354	319,987
Accumulated other comprehensive loss	(131)	(59)
Total shareholders' equity	212,838	520,745
Total liabilities and shareholders' equity	$ 907,326	$ 1,218,238

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2020	**2019**	**2018**
Cash flows from operating activities			
Net income (loss)	$ (310,557)	$ 70,589	$ 224,785
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Non-cash reorganization items	—	—	(3,322)
Depreciation, depletion and amortization	140,673	174,569	127,961
Impairments of oil and gas properties	391,849	—	—
Derivative contracts:			
Net (gains) losses	(88,422)	68,131	(37,427)
Cash settlements and premiums received (paid), net	78,087	(4,136)	(48,291)
Deferred income tax expense (benefit)	(1,424)	3,373	2,994
Loss (gain) on sales of assets, net	(18)	(5)	177
Non-cash interest expense	4,150	3,354	3,416
Share-based compensation	3,284	4,082	4,618
Other, net	31	52	44
Changes in operating assets and liabilities:			
Accounts receivable, net	28,078	(5,079)	(23,674)
Accounts payable and accrued expenses	(24,731)	4,690	21,109
Other assets and liabilities	778	574	(258)
Net cash provided by operating activities	221,778	320,194	272,132
Cash flows from investing activities			
Acquisitions, net	—	(6,516)	(85,387)
Capital expenditures	(168,565)	(362,743)	(430,592)
Proceeds from sales of assets, net	87	215	7,683
Net cash used in investing activities	(168,478)	(369,044)	(508,296)
Cash flows from financing activities			
Proceeds from credit facility borrowings	51,000	76,400	244,000
Repayment of credit facility borrowings	(99,000)	(35,000)	—
Debt issuance costs paid	(78)	(2,616)	(989)
Net cash provided by (used in) financing activities	(48,078)	38,784	243,011
Net increase (decrease) in cash and cash equivalents	5,222	(10,066)	6,847
Cash and cash equivalents - beginning of period	7,798	17,864	11,017
Cash and cash equivalents - end of period	$ 13,020	$ 7,798	$ 17,864
Supplemental disclosures:			
Cash paid for:			
Interest, net of amounts capitalized	$ 27,333	$ 32,398	$ 22,599
Income taxes, net of (refunds)	$ (2,471)	$ (2,471)	$ —
Reorganization items, net	$ —	$ 79	$ 540
Non-cash investing and financing activities:			
Changes in accounts receivable, net related to acquisitions	$ —	$ (152)	$ (27,107)
Changes in other assets related to acquisitions	$ —	$ —	$ (743)
Changes in accrued liabilities related to acquisitions	$ —	$ (540)	$ (11,182)
Changes in accrued liabilities related to capital expenditures	$ (18,671)	$ (3,602)	$ 44
Changes in other liabilities for asset retirement obligations related to acquisitions	$ —	$ 83	$ 385

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 Other Comprehensive Income (Loss)	Total Shareholders' Equity
December 31, 2017	15,019	$ —	$ 150	$ 194,123	$ 27,366	$ —	$ 221,639
Net income	—	—	—	—	224,785	—	224,785
Share-based compensation	—	—	—	4,618	—	—	4,618
Restricted stock unit vesting	61	—	1	(1,111)	—	—	(1,110)
Cumulative effect of change in accounting principle (see Note 2)	—	—	—	—	(2,659)	—	(2,659)
All other changes	—	—	—	—	—	82	82
December 31, 2018	15,080	—	151	197,630	249,492	82	447,355
Net income	—	—	—	—	70,589	—	70,589
Share-based compensation	—	—	—	4,082	—	—	4,082
Restricted stock unit vesting	56	—	—	(1,046)	—	—	(1,046)
Cumulative effect of change in accounting principle (see Note 2)	—	—	—	—	(94)	—	(94)
All other changes	—	—	—	—	—	(141)	(141)
December 31, 2019	15,136	—	151	200,666	319,987	$ (59)	520,745
Net loss	—	—	—	—	(310,557)	—	(310,557)
Share-based compensation	—	—	—	3,284	—	—	3,284
Restricted stock unit vesting	64	—	1	(487)	—	—	(486)
Cumulative effect of change in accounting principle (see Note 5)	—	—	—	—	(76)	—	(76)
All other changes	—	—	—	—	—	(72)	(72)
December 31, 2020	15,200	$ —	$ 152	$ 203,463	$ 9,354	$ (131)	$ 212,838

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 focused on the onshore exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas. 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.

2. Basis of Presentation

Adoption of Recently Issued Accounting Pronouncements and Comparability to Prior Periods

Effective January 1, 2020, we adopted and began applying the relevant guidance provided in the Financial Accounting Standards Board's ("FASB") Accounting Standards Update ("ASU") ASU 2016–13, *Measurement of Credit Losses on Financial Instruments* ("ASU 2016–13"). We adopted ASU 2016–13 using the optional transition approach with a charge to the beginning balance of retained earnings as of January 1, 2020 (see Note 5 for the impact and disclosures associated with the adoption of ASU 2016–13).

Effective January 1, 2019, we adopted and began applying the relevant guidance provided in ASU 2016–02, *Leases* ("ASU 2016–02") and related amendments to accounting principles generally accepted in the United States of America ("GAAP") which, together with ASU 2016–02, represent Accounting Standards Codification ("ASC") Topic 842, *Leases* ("ASC Topic 842"). We adopted ASC Topic 842 using the optional transition approach with a charge of $0.1 million to the beginning balance of retained earnings as of January 1, 2019.

Effective January 1, 2018, we adopted and began applying the relevant guidance provided in ASU 2014–09, *Revenues from Contracts with Customers* ("ASU 2014–09") and related amendments to GAAP which, together with ASU 2014–09, represent ASC Topic 606, *Revenues from Contracts with Customers* ("ASC Topic 606"). We adopted ASC Topic 606 using the cumulative effect transition method and wrote off $2.7 million of accounts receivable arising from natural gas imbalances accounted for under the entitlements method as a direct reduction to our beginning balance of retained earnings as of January 1, 2018.

Comparative periods and related disclosures have not been restated for the application of ASU 2016–13 and ASC Topic 842. Accordingly, certain components of our Consolidated Financial Statements are not comparable between periods and the Consolidated Statement of Operations for the years ended December 31, 2019 and 2018 are presented based on prior GAAP for credit losses and leases, respectively, in their entirety.

Subsequent Events

At a special meeting held on January 13, 2021, the Company's shareholders approved the potential issuance of up to 22,597,757 shares of our common stock, par value $0.01 per share (the "Common Stock"), upon the redemption or exchange of up to 225,977.57 shares of Series A Preferred Stock, par value $0.01 per share, of the Company ("Series A Preferred Stock"), together with up to 22,597,757 common units representing limited partner interests (the "Common Units") of PV Energy Holdings, L.P. (the "Partnership"). On January 14, 2021, the Company amended its articles of incorporation (the "Articles of Amendment") creating a series of the Company's preferred stock consisting of 300,000 shares and designated as the Series A Preferred Stock, as well as establishing the powers, preferences and rights of the preferred stock series and the qualifications, limitations and restrictions thereof.

On January 15, 2021, or the Closing Date, the Company consummated the previously announced transactions, (collectively, the "Juniper Transactions"), contemplated by: (i) the Contribution Agreement, dated November 2, 2020 (the "Contribution Agreement"), by and among the Company, the Partnership, and JSTX Holdings, LLC ("JSTX"), an affiliate of Juniper Capital Advisors, L.P. ("Juniper Capital"), and, together with its affiliates ("Juniper"); and (ii) the Contribution Agreement, dated November 2, 2020 (the "Asset Agreement," and, together with the Contribution Agreement, the "Juniper Transaction Agreements"), by and among Rocky Creek Resources, LLC, an affiliate of Juniper Capital ("Rocky Creek"), the Company and the Partnership.

In connection with the consummation of the Juniper Transactions, the Company completed a reorganization into an up-C structure (the "Reorganization") (which is intended to, among other things, result in the holders of the Series A Preferred Stock, having a voting interest in the Company that is commensurate with such holders' economic interest in the Partnership), including (i) the conversion of each of the Company's corporate subsidiaries into limited liability companies which are disregarded for U.S. federal income tax purposes, including the conversion of Penn Virginia Holding Corp. into Penn Virginia Holdings, LLC, a Delaware limited liability company ("Holdings"), and (ii) the Company's contribution of all of its equity interests in Holdings to the Partnership in exchange for 15,268,686 newly issued Common Units.

On the Closing Date, (i) pursuant to the terms of the Contribution Agreement, JSTX contributed to the Partnership, as a capital contribution, $150 million in cash in exchange for 17,142,857 newly issued Common Units and the Company issued to JSTX 171,428.57 shares of Series A Preferred Stock at a price equal to the par value of the shares acquired, and (ii) pursuant to the terms of the Asset Agreement, Rocky Creek contributed to our operating subsidiary certain oil and gas assets in exchange for 5,405,252 newly issued Common Units and the Company issued to Rocky Creek 54,052.52 shares of Series A Preferred Stock at a price equal to the par value of the shares acquired, including 495,900 Common Units and 4,959 shares of Series A Preferred Stock placed in an indemnity escrow to support post-closing indemnification claims, 50% of such escrowed amount to be disbursed 180 days after the Closing and the remainder one year after the Closing.

Concurrent with the closing of the Juniper Transaction, on the Closing Date, the following transactions occurred: (i) the Agreement and Amendment No. 9 to Credit Agreement (the "Ninth Amendment") to the credit agreement (the "Credit Facility") became effective and a prepayment of $80.5 million of outstanding borrowings under the Credit Facility was made plus accrued interest of $0.1 million, (ii) the amendment dated November 2, 2020 (the "Second Lien Amendment") to the Second Lien Credit Agreement dated as of September 29, 2017 (the "Second Lien Facility") became effective and a prepayment of $50.0 million of outstanding advances under the Second Lien Facility was made plus accrued interest of $0.2 million in accordance with the Second Lien Amendment, (iii) total payments of $17.8 million in cash were completed for transaction and debt issue costs, including (A) $16.0 million associated with the Juniper Transactions, (B) $1.4 million associated with the Second Lien Amendment and (C) $0.4 million associated with the Ninth Amendment and (iv) a combined payment of $1.3 million including principal and accrued interest was made to liquidate the outstanding advances attributable to a single participant lender.

We incurred a total of $18.5 million for certain professional fees, including advisory, legal, consulting fees and other costs in connection with the Juniper Transactions. A total of $5.0 million were attributable to services and costs incurred in 2020. The remaining $13.5 million includes $5.5 million of costs incurred by Juniper that were to be paid by the Company as a condition of closing the Juniper Transaction Agreements as well as $8.0 million of other fees and costs that were incurred in January 2021 or otherwise incurred contingent upon the closing. All of the costs incurred in 2020 have been recognized in general and administrative expenses ("G&A"). Of the costs incurred in January 2021 and those associated with the closing, $4.2 million will be recognized as a component of G&A and $9.3 million, including the aforementioned $5.5 million of costs incurred by Juniper and $3.8 million of costs incurred by us related to the issuance of the Series A Preferred Stock and Common Units, will be classified as a reduction to the capital contribution on our Consolidated Balance Sheet.

Following the Juniper Transactions, Edward Geiser, Juniper's Managing Partner, began serving as Penn Virginia's Chairman of the Board, and Juniper appointed four additional members to the Board. Darrin Henke and the other members of our senior management are continuing in their roles, and the Company's current directors, including Mr. Henke, have remained on the Board following the closing.

Management has evaluated all of our activities through the issuance date of our Consolidated Financial Statements and has concluded that, other than the aforementioned Juniper Transactions, the Ninth Amendment (see Note 9), the Second Lien Amendment (see Note 9), no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes thereto.

Risks and Uncertainties

As an oil and gas exploration and development company, we are exposed to a number of risks and uncertainties that are inherent to our industry. The global public health crisis associated with the novel coronavirus ("COVID-19") has, and is anticipated to continue to have, an adverse effect on global economic activity for the immediate future and has resulted in travel restrictions, business closures, limitations to person-to-person contact and the institution of quarantining and other restrictions on movement in many communities. The slowdown in global economic activity attributable to COVID-19 resulted in a dramatic decline in the demand for energy in 2020, which directly impacts our industry and the Company. In addition, global crude oil prices experienced a collapse that began in early March 2020 as a direct result of disagreements between the Organization of the Petroleum Exporting Countries ("OPEC") and Russia (together with OPEC, collectively "OPEC+") with respect to production curtailments. OPEC+ ultimately agreed to specified adjustments to production in the Spring of 2020 which, for the most part, held for the remainder of the year and were supplemented by additional voluntary downward adjustments, led primarily by Saudi Arabia. Collectively these curtailments have contributed to a relative stabilization of commodity prices and rebalancing of the global crude oil markets by the end of 2020.

Notwithstanding the relative improvement in global market stability, as a result of several factors including rising infection rates at the beginning of 2021, mutating strains of the virus, the return of stricter lockdown measures and logistical challenges in vaccine distribution, among others, a return to pre-COVID 19 levels of economic activity remain uncertain in their magnitude and eventual timing. Nonetheless, OPEC+ indicated in their January 2021 meeting a commitment to gradually return limited production to the market with the pace being determined by market conditions. An additional meeting is scheduled for early March of 2021 to monitor conditions and progress.

A significant decline in domestic drilling by U.S. producers began in mid-March 2020 and continued through most of the second half of the year. The overall economic decline had an adverse impact on the entire industry, but particularly on smaller upstream producers with limited financial resources as well as oilfield service companies. While a modest recovery in activity began in the fourth quarter of 2020, including a resumption of our own drilling program, domestic supply and demand imbalances continue to stress the market which is further exacerbated by capacity limitations associated with storage, pipeline and refining infrastructure, particularly within the Gulf Coast region.

While there exists encouraging signs for continued recovery due to the aforementioned vaccine development as well as a commitment by the new U.S. Administration to prioritize economic relief efforts, the relative success of such efforts is difficult to predict with respect to timing and the resulting economic impact. Accordingly, the combined effect of the global and domestic factors discussed herein is anticipated to continue to contribute to overall volatility within the industry generally and to our operations specifically.

During 2020, we initiated several actions to mitigate the anticipated adverse economic conditions for the immediate future and to support our financial position and liquidity. The more significant actions that we took during that time included: (i) temporarily suspending our drilling program from April through September 2020, (ii) curtailing production through selected well shut-ins for a period of several weeks in April and May, (iii) securing additional crude oil storage capacity (see Note 14) in order to maintain a reasonable level of production to (a) allow for the continued marketing of NGLs and natural gas rather than delaying revenues through additional shut-ins and (b) capitalize on potential increases in commodity prices, (iv) substantially expanding the scope and range of our commodity derivatives portfolio (see Note 6), (v) utilizing certain provisions of the Coronavirus Aid, Relief and Economic Security Act (the “CARES Act”) and related regulations, the most significant of which resulted in the receipt in June 2020 of an accelerated refund of our remaining refundable alternative minimum tax (“AMT”) credit carryforwards in the amount of $2.5 million and (vi) elimination of annual cost-of-living and similar adjustments to our salaries and wages for 2020, and in July 2020, a limited reduction-in-force (“RIF”). We incurred and paid employee termination and severance benefits of approximately $0.2 million in connection with the limited RIF and those costs have been included in G&A.

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

We utilize derivative instruments, which are placed with financial institutions that we believe are of acceptable credit risk, to mitigate our financial exposure to commodity price and interest rate volatility. 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. We have elected to report all of our derivative asset and liability positions on a gross basis on our Consolidated Balance Sheet and not net the positions, even when a legal right-of-setoff exists. Our derivative instruments are not formally designated as hedges in the context of GAAP. In accordance with our internal policies, we do not utilize derivative instruments for speculative purposes. We recognize changes in fair value in earnings currently as a component of the Derivatives caption in our Consolidated Statements of Operations.

Oil and Gas Properties

We apply the full cost method of accounting 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 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 after-tax discounted future net revenues from proved properties adjusted for costs excluded from amortization (the "Ceiling Test"). The estimated after-tax discounted future net revenues are determined using the prior 12-month's average commodity prices 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.

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.

Other Property and Equipment

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

We compute depreciation and amortization of property and equipment using the straight-line 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.

Leases

We determine if an arrangement is a lease at the inception of the underlying contractual arrangement. In addition, we determine whether the lease is classified as operating or financing. Leases are included in the captions “Other assets,” “Accounts payable and accrued liabilities” and “Other liabilities” on our Consolidated Balance Sheets and are identified as Right-of-use (“ROU”) assets, Current lease obligations and Noncurrent lease obligations, respectively, in Notes 11 and 12.

ROU assets represent our right to use an underlying asset for the lease term and lease obligations represent our obligation to make lease payments arising from the underlying contractual arrangement. Operating lease ROU assets and obligations are recognized at the commencement date based on the present value of lease payments over the lease term. The operating lease ROU assets include any lease payments made in advance and excludes lease incentives. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that we will exercise such options. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term.

Most of our leasing arrangements do not identify or otherwise provide for an implicit interest rate. Accordingly, we utilize a secured incremental borrowing rate based on information available at the commencement date in the determination of the present value of the lease payments. As most of our lease arrangements have terms ranging from two to 5 years, our secured incremental borrowing rate is primarily based on the rates applicable to our Credit Facility.

We have lease arrangements that include lease and certain non-lease components, including amounts for related taxes, insurance, common area maintenance and similar terms. We apply a practical expedient provided in ASC Topic 842 to not separate the lease and non-lease components. Accordingly, the ROU assets and lease obligations for such leases will include the present value of the estimated payments for the non-lease components over the lease term.

Certain of our lease arrangements with contractual terms of 12 months or less are classified as short-term leases. Accordingly, we do not include the underlying ROU assets and lease obligations on our Consolidated Balance Sheets. The associated costs are aggregated with all of our other lease arrangements and are disclosed in the tables in Note 11.

Certain of our lease arrangements result in variable lease payments which, in accordance with ASC Topic 842, do not give rise to lease obligations. Rather, the basis and terms and conditions upon which such variable lease payments are determined are disclosed in Note 11.

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 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 it may be incurred, as a component of interest expense and penalties as a component of income tax expense.

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

Revenue Recognition and Associated Costs

Substantially all of our commodity product sales are short-term in nature with contract terms of one year or less. We apply a practical expedient which provides for an exemption from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. Under our commodity product sales contracts, we bill our customers and recognize revenue when our performance obligations have been satisfied. At that time, we have determined that payment is unconditional. Accordingly, our commodity sales contracts do not create contract assets or liabilities.

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

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

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

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

Marketing and water disposal services. We provide marketing and water disposal services to certain of our joint venture partners and other third parties with respect to oil and gas production for which we are the operator. Pricing for such services represents a fixed rate fee based, in the case of marketing services, on the sales price of the underlying oil and gas products and, in the case of water services, on the quantity of water volume processed. Marketing revenue is recognized simultaneously with the sale of our commodity production to our customers while water service revenue is recognized in the month that the service is rendered. Direct costs associated with our marketing efforts are included in G&A expenses and direct costs associated with our water service efforts are netted against the underlying revenue.

Credit Losses

We monitor and assess our portfolio of accounts receivable, including those from our customers, our joint interest partners and others, when applicable, for credit losses on a monthly basis as we originate the underlying financial assets. Our review process and related internal controls take into appropriate consideration (i) past events and historical experience with the identified portfolio segments, (ii) current economic and related conditions within the broad energy industry as well as those factors with broader applicability and (iii) reasonable supportable forecasts consistent with other estimates that are inherent in our financial statements. In order to facilitate our processes for the review and assessment of credit losses, we have identified the following portfolio segments: (i) customers for our commodity production and (ii) joint interest partners which are further stratified into the following sub-segments: (a) mutual operators which includes joint interest partners with whom we are a non-operating joint interest partner in properties for which they are the operator, (b) large partners consisting of those legal entities that maintain a working interest of at least 10 percent in properties for which we are the operator and (c) all others which includes legal entities that maintain working interests of less than 10 percent in properties for which we are the operator as well as legal entities with whom we no longer have an active joint interest relationship, but continue to have transactions, including joint venture audit settlements, that from time-to-time give rise to the origination of new accounts receivable.

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 equity-classified awards are generally amortized on a straight-line basis over the applicable vesting period except for those that are based on performance which are amortized on a graded basis over the term of the applicable performance periods. Compensation cost associated with 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. We recognize forfeitures as they occur. We recognize share-based compensation expense related to our share-based compensation plans as a component of G&A in our Consolidated Statements of Operations.

Reorganization Items

Includes adjustments directly attributable to the final administration and discharge of our bankruptcy case in connection with a final decree that was issued in November 2018 and that are not a part of our continuing operations.

4. Acquisitions and Divestitures

Acquisitions

Eagle Ford Working Interests

In 2019, we acquired working interests in certain properties for which we are the operator from our joint venture partners in a series of transactions for cash consideration of $6.5 million. Funding for these acquisition was provided by borrowings under the Credit Facility.

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, covering approximately 9,700 net acres primarily in Gonzales County, Texas for $86.0 million in cash (the "Hunt Acquisition"). The Hunt Acquisition had an effective date of October 1, 2017 and closed in 2018. We paid total cash consideration of $83.0 million, net of suspended revenues received, for the Hunt Acquisition in 2018. We also acquired working interests in certain wells that we previously drilled as operator in which Hunt had rights to participate prior to the transaction closing. Accumulated costs, net of suspended revenues for these wells was $13.8 million, along with $0.2 million of certain working capital adjustments which we have reflected as components of the total net assets acquired. We funded the Hunt Acquisition with borrowings under the Credit Facility.

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

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

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

Valuation of Acquisition

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

Impact of Acquisition on Actual and Pro Forma Results of Operations

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

The following table presents unaudited summary pro forma financial information for the year ended December, 31, 2018 assuming the Hunt Acquisition occurred as of January 1, 2017. The pro forma financial information does not purport to represent what our actual results of operations would have been if the Hunt Acquisitions had occurred as of this date, or the results of operations for any future periods.

Total revenues	$	446,077
Net income	$	227,930
Net income per share - basic	$	15.14
Net income per share - diluted	$	14.91

Divestitures

Mid-Continent Divestiture

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

The Mid-Continent properties had AROs of $0.3 million as well as a net working capital deficit attributable to the oil and gas properties of $1.3 million as of July 31, 2018. The net pre-tax operating income attributable to the Mid-Continent assets was $1.6 million for the year ended December 31, 2018.

Sales of Undeveloped Acreage, Rights and Other Assets

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

5. Accounts Receivable and Revenues from Contracts with Customers

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

	December 31,	
	2020	2019
Customers	$ 39,672	$ 63,165
Joint interest partners	3,079	6,929
Other	8	674
	42,759	70,768
Less: Allowance for credit losses	(197)	(52)
	$ 42,562	$ 70,716

Revenue from Contracts with Customers

For the year ended December 31, 2020, three customers accounted for $150.8 million, or approximately 56% of our consolidated product revenues. The revenues generated from these customers during 2020 were $72.3 million, $50.2 million, and $28.3 million or 27%, 19%, and 10% of the consolidated total, respectively. As of December 31, 2020, $18.6 million, or approximately 47% of our consolidated accounts receivable from customers was related to these customers. For the year ended December 31, 2019, four customers accounted for $354.6 million, or approximately 76% of our consolidated product revenues. The revenues generated from these customers during 2019 were $172.3 million, $84.6 million, $50.7 million and $47.0 million or approximately 37%, 18%, 11% and 10% of the consolidated total, respectively. As of December 31, 2019, $44.5 million, or approximately 70% of our consolidated accounts receivable from customers was related to these customers.

Credit Losses and Allowance for Credit Losses

Adoption of ASU 2016–13

Effective January 1, 2020, we adopted ASU 2016–13 and have applied the guidance therein to our portfolio of accounts receivable including those from our customers and our joint interest partners. We have adopted ASU 2016–13 using the modified retrospective method resulting in an adjustment of less than $0.1 million to the beginning balance of retained earnings and a corresponding increase to the allowance for credit losses as of January 1, 2020. As of December 31, 2020, the allowance for credit losses is entirely attributable to certain receivables from joint interest partners as described below.

Customers. We sell our commodity products to approximately 20 customers. A substantial majority of these customers are large, internationally recognized refiners and marketers in the case of our crude oil sales and large domestic processors and interstate pipelines with respect to our NGL and natural gas sales. As noted in our disclosures regarding major customers above, a significant portion of our outstanding customer accounts receivable are concentrated within a group of up to five customers at any given time. Due primarily to the historical market efficiencies and generally timely settlements associated with commodity sale transactions for crude oil, NGLs and natural gas, we have assessed this portfolio segment at zero risk for credit loss upon the adoption of ASU 2016–13 and for each of the periods included in the year ended December 31, 2020. Historically, we have never experienced a credit loss with such customers. No significant uncertainties exist related to the collectability of amounts owed to us by any of these customers.

Mutual Operators. As of December 31, 2020, we had mutual joint interest partner relationships with two upstream producers that also operate properties within the Eagle Ford for which we have non-operated working interests. Historically we have had full and timely collection experiences with these entities and we ourselves are timely with respect to our payments to them of joint venture costs. Upon adoption of ASU 2016–13, we had assessed this portfolio segment at zero risk for credit loss; however, in light of the potential for liquidity concerns due to current economic conditions in the near-term, we have assessed receivables originating in 2020 with a 5 percent risk.

Large Partners. As of December 31, 2020, three legal entities had working interests of 10 percent or greater in properties that we operate. These entities are primarily passive investors. Historically we have had full and timely collection experiences with these entities. Upon adoption of ASU 2016–13, we had assessed this portfolio segment at a risk of 1 percent for credit loss; however, in light of the potential for liquidity concerns due to current economic conditions in the near-term, we have increased the assessed receivables originating in 2020 to a 2 percent risk.

All Others. As of December 31, 2020, approximately 20 legal entities had working interests of less than 10 percent in properties that we operate. Historically, this is the only portfolio segment with whom we have experienced credit losses. Generally, this group includes passive investors and smaller producers that may not have the wherewithal or alternative sources of liquidity to settle their obligations to us in the event of individual challenges unique to smaller entities as well as adverse economic conditions in general. Upon adoption of ASU 2016–13, we had assessed this portfolio segment at a risk of 5 percent for credit loss; however, in light of the potential for liquidity concerns due to current economic conditions in the near-term, we have increased the assessed receivables originated in 2020 to a 10 percent risk. As of December 31, 2020, approximately $0.2 million of accounts receivables attributable to this portfolio segment was past due, or over 60 days.

The following table summarizes the activity in our allowance for credit losses, by portfolio segment, for the year ended December 31, 2020:

		Joint Interest Partners			
	Customers	Mutual Operators	Large Partners	All Others	Total
Balance at beginning of period	$ —	$ —	$ —	$ 52	$ 52
Adjustment upon adoption	—	—	60	16	76
Provision for expected credit losses	—	9	27	33	69
Write-offs and recoveries	—	—	—	—	—
Balance at end of period	$ —	$ 9	$ 87	$ 101	$ 197

6. Derivative Instruments

We utilize derivative instruments, typically swaps, put options and call options which are placed with financial institutions that we believe are acceptable credit risks, to mitigate our financial exposure to commodity price volatility associated with anticipated sales of our future production and volatility in interest rates attributable to our variable rate debt instruments. Our derivative instruments are not formally designated as hedges in the context of GAAP. While the use of derivative instruments limits the risk of adverse commodity price and interest rate movements, such use may also limit the beneficial impact of future product revenues and interest expense from favorable commodity price and interest rate movements. From time to time, we may enter into incremental derivative contracts in order to increase the notional volume of production we are hedging, restructure existing derivative contracts or enter into other derivative contracts resulting in modification to the terms of existing contracts. In accordance with our internal policies, we do not utilize derivative instruments for speculative purposes.

Commodity Derivatives

The following is a general description of the commodity derivative instruments we have employed:

Swaps. A swap contract is an agreement between two parties pursuant to which the parties exchange payments at specified dates on the basis of a specified notional amount, or the swap price, with the payments calculated by reference to specified commodities or indexes. The purchasing counterparty to a swap contract is required to make a payment to selling counterparty based on the amount of the swap price in excess of the settlement price multiplied by the notional volume if the settlement price for any settlement period is below the swap price for such contract. We are required to make a payment to the counterparty based on the amount of the settlement price in excess of the swap price multiplied by the notional volume if the settlement price for any settlement period is above the swap price for such contract.

Put Options. A put option has a defined strike, or floor price. We have entered into put option contracts in the roles of buyer and seller depending upon our particular hedging objective. The buyer of the put option pays the seller a premium to enter into the contract. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the notional volume. When the settlement price is above the floor price, the put option expires worthless. Certain of our purchased put options have deferred premiums. For the deferred premium puts, we agree to pay a premium to the counterparty at the time of settlement.

Call Options. A call option has a defined strike, or ceiling price. We have entered into call option contracts in the roles of buyer and seller depending upon our particular hedging objective. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the notional volume. When the settlement price is below the ceiling price, the call option expires worthless.

We typically combine swaps, purchased put options, purchased call options, sold put options and sold call options in order to achieve various hedging objectives. Certain of these objectives result in combinations that operate as collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap, among others.

We determine the fair values of our commodity derivative instruments using industry-standard models that consider various assumptions, including current market value and contractual prices for the underlying instruments, implied volatilities, time value and nonperformance risk. For the current market prices, we use third-party quoted forward prices, as applicable, for NYMEX West Texas Intermediate ("NYMEX WTI"), Magellan East Houston ("MEH") crude oil and NYMEX Henry Hub ("NYMEX HH") natural gas closing prices as of the end of the reporting period. Nonperformance risk is incorporated by utilizing 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.

The following table sets forth our commodity derivative contracts as of December 31, 2020:

	1Q2021	2Q2021	3Q2021	4Q2021	1Q2022	2Q2022	3Q2022	4Q2022	1Q2023	2Q2023
NYMEX WTI Crude Swaps										
Average Volume Per Day (barrels)	3,889	3,297	815	815						
Weighted Average Swap Price ($/barrel)	$ 54.38	$ 55.89	$ 45.54	45.54						
NYMEX WTI Crude Collars										
Average Volume Per Day (barrels)	9,722	10,440	9,239	8,152	2,917	2,885	2,853	2,853	2,917	2,855
Weighted Average Purchased Put Price ($/barrel)	$ 40.00	$ 42.84	$ 40.35	$ 40.40	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Weighted Average Sold Call ($/barrel)	$ 45.78	$ 51.70	$ 51.85	$ 52.10	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00
NYMEX WTI Purchased Puts										
Average Volume Per Day (barrels)	1,667									
Weighted Average Purchased Put Price ($/barrel)	$ 55.00									
NYMEX WTI Sold Puts										
Average Volume Per Day (barrels)	556	11,538	5,707	5,707						
Weighted Average Sold Put ($/barrel)	$ 26.50	$ 36.93	$ 35.14	35.14						
MEH-NYMEX WTI Crude Basis Swaps										
Average Volume Per Day (barrels)	8,889									
Weighted Average Swap Price ($/barrel)	$ 1.16									
NYMEX WTI Crude CMA Roll Basis Swaps										
Average Volume Per Day (barrels)	14,444	13,187	13,043	13,043						
Weighted Average Swap Price ($/barrel)	$ (0.18)	$ 0.07	$ 0.07	$ 0.07						
NYMEX HH Collars										
Average Volume Per Day (MMBtus)	10,000	9,890	9,783	9,783						
Weighted Average Purchased Put Price ($/MMBtu)	$ 2.607	$ 2.607	$ 2.607	$ 2.607						
Weighted Average Sold Call ($/MMBtu)	$ 3.117	$ 3.117	$ 3.117	$ 3.117						
NYMEX HH Sold Puts										
Average Volume Per Day (MMBtus)	6,667	6,593	6,522	6,522						
Weighted Average Sold Put Strike ($/MMBtu)	$ 2.000	$ 2.000	$ 2.000	$ 2.000						

As of December 31, 2020, we were unhedged with respect to NGL production.

Interest Rate Derivatives

We have entered into a series of interest rate swap contracts (the “Interest Rate Swaps”) to establish fixed interest rates on a portion of our variable interest rate indebtedness under the Credit Facility and the Second Lien Facility. The notional amount of the Interest Rate Swaps totals $300 million, with us paying a weighted average fixed rate of 1.36% on the notional amount, and the counterparties paying a variable rate equal to LIBOR through May 2022.

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 effects of derivative gains and (losses) and cash settlements 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 (gains) losses” and “Cash settlements and premiums received (paid), net.”

The following table summarizes the effects of our derivative activities for the periods presented:

	Year Ended December 31,		
	2020	**2019**	**2018**
Interest rate swap losses recognized in the Consolidated Statements of Operations	$ (7,510)	$ —	$ —
Commodity gains (losses) recognized in the Consolidated Statements of Operations	95,932	(68,131)	37,427
	$ 88,422	$ (68,131)	$ 37,427
Interest rate cash settlements recognized in the Consolidated Statements of Cash Flows	$ (2,210)	$ —	$ —
Commodity cash settlements and premiums received (paid) recognized in the Consolidated Statements of Cash Flows	80,297	(4,136)	(48,291)
	$ 78,087	$ (4,136)	$ (48,291)

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, 2020		**December 31, 2019**	
Type	**Balance Sheet Location**	**Derivative Assets**	**Derivative Liabilities**	**Derivative Assets**	**Derivative Liabilities**
Interest rate contracts	Derivative assets/liabilities – current	$ —	$ 3,655	$ —	$ —
Commodity contracts	Derivative assets/liabilities – current	78,793	81,772	4,131	23,450
Interest rate contracts	Derivative assets/liabilities – noncurrent	—	1,645	—	—
Commodity contracts	Derivative assets/liabilities – noncurrent	25,449	26,789	2,750	3,385
		$ 104,242	$ 113,861	$ 6,881	$ 26,835

As of December 31, 2020, we reported net commodity derivative liabilities of $4.3 million and net Interest Rate Swap liabilities of $5.3 million. The contracts associated with these position are with eight counterparties for commodity derivatives and four counterparties for Interest Rate Swaps, all of which are investment grade financial institutions and are participants in the Credit Facility. This concentration may impact our overall credit risk in that these counterparties may be similarly affected by changes in economic or other conditions.

We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

7. Property and Equipment

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

	December 31, 2020	December 31, 2019
Oil and gas properties:		
Proved	$ 1,545,910	$ 1,409,219
Unproved	49,935	53,200
Total oil and gas properties	1,595,845	1,462,419
Other property and equipment	27,746	25,915
Total property and equipment	1,623,591	1,488,334
Accumulated depreciation, depletion and amortization	(900,042)	(367,909)
	$ 723,549	$ 1,120,425

Unproved property costs of $49.9 million and $53.2 million have been excluded from amortization as of December 31, 2020 and December 31, 2019, respectively. An additional $1.2 million of costs, associated with wells in-progress for which we had not previously recognized any proved undeveloped reserves, were excluded from amortization as of December 31, 2020. The total costs not subject to amortization as of December 31, 2020 were incurred in the following periods: $2.2 million in 2020, $1.6 million in 2019, $2.0 million in 2018 and $44.2 million prior to 2018 as well as $1.1 million of capitalized interest applied thereto. We transferred $8.3 million and $16.8 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 years ended December 31, 2020 and 2019, respectively. We capitalized internal costs of $2.1 million, $4.1 million and $3.7 million and interest of $2.7 million, $4.1 million and $9.1 million during the year ended December 31, 2020, 2019 and 2018 respectively, in accordance with our accounting policies. Average DD&A per BOE of proved oil and gas properties was $15.83, $17.25 and $16.11 for the years ended December 31, 2020, 2019 and 2018, respectively.

As of December 31, 2020, the carrying value of our proved oil and gas properties exceeded the limit determined by the Ceiling Test by $120.3 million. Accordingly, we recorded an impairment of our oil and gas properties by this amount for the three months ended December 31, 2020, and when combined with the $271.5 million record in the first nine months of 2020, $391.8 million for the year ended December 31, 2020. Because the Ceiling Test utilizes commodity prices based on a trailing twelve month average, as of December 31, 2020 it does not fully reflect the substantial decline in commodity prices that accelerated early in the second quarter of 2020 due to the economic impact of the COVID-19 pandemic and the ongoing disruption in global energy markets. Accordingly, we may incur an additional impairment during the first quarter of 2021.

8. Asset Retirement Obligations

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

	Year Ended December 31, 2020	Year Ended December 31, 2019
Balance at beginning of period	$ 4,934	$ 4,314
Changes in estimates	33	(2)
Liabilities incurred	121	290
Liabilities settled	—	(67)
Acquisitions of properties	16	83
Accretion expense	357	316
Balance at end of period	$ 5,461	$ 4,934

9. Long-Term Debt

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

	December 31, 2020		December 31, 2019	
	Principal	Unamortized Discount and Issuance Costs [1, 2]	Principal	Unamortized Discount and Issuance Costs [1, 2]
Credit facility	$ 314,400		$ 362,400	
Second lien term loan	200,000	$ 4,903	200,000	$ 7,372
Totals	514,400	4,903	562,400	7,372
Less: Unamortized discount ("OID") [2]	(1,604)		(2,415)	
Less: Unamortized deferred issuance costs [1, 2]	(3,299)		(4,957)	
Long-term debt, net	$ 509,497		$ 555,028	

[1] Excludes 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 12) and are being amortized over the term of the Credit Facility using the straight-line method.

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

Credit Facility

The Credit Facility provides for a $1.0 billion revolving commitment and a $375 million borrowing base including a $25 million sublimit for the issuance of letters of credit. Availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base; however, outstanding borrowings under the Credit Facility are limited to a maximum of $350 million until the next redetermination of the borrowing base. The borrowing base under the Credit Facility is redetermined semi-annually, generally in the Spring and Fall of each year. Additionally, we and the Credit Facility lenders may, upon request, initiate a redetermination at any time during the six-month period between scheduled redeterminations. Certain minimum hedging and other conditions included in the Ninth Amendment were initially satisfied in February 2021 which allow for a borrowing base holiday until Fall 2021 assuming we continue to satisfy the conditions. The Credit Facility is available to us for general corporate purposes, including working capital. The Credit Facility is scheduled to mature in May 2024. We had $0.4 million in letters of credit outstanding as of December 31, 2020 and 2019.

In the years ended December 31, 2020 and 2019, we incurred and capitalized issue costs of $0.1 million and $2.6 million, respectively, in connection with amendments to the Credit Facility and wrote off $0.9 million of previously capitalized issue costs due to a decrease in the borrowing base associated with an amendment during the first half of 2020. We incurred and capitalized $0.4 million of issue costs in January 2021 in connection with the Ninth Amendment. In addition to the requirement to repay outstanding borrowings of $80.5 million under the Credit Facility from the proceeds of the Juniper Transactions, the Ninth Amendment provides for: (i) the aforementioned borrowing base holiday, (ii) introduces a first lien leverage ratio covenant of 2.50 times, tested quarterly and (iii) permits amortization payments of up to $1.875 million per quarter to be made under the Second Lien Facility until January 2022 if no default exists both before and after giving effect to the payments and thereafter using available free cash flow upon the satisfaction of certain conditions (including maintaining a leverage ratio of 2.00 to 1.00 and availability of at least 25% under the Credit Facility after giving pro forma effect to the payment). In addition, the Ninth Amendment provides for a minimum hedge condition that further limits the type of instruments to be utilized, the notional volume to be hedged and sets a minimum floor price for certain contracts as well as a provision for the replacement of the LIBOR interest rate upon its expiration in 2022.

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 1.50% to 2.50%, determined based on the utilization level under the Credit Facility or (b) a Eurodollar rate, including LIBOR through 2021, plus an applicable margin ranging from 2.50% to 3.50%, determined based on the utilization level 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 Eurodollar 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, 2020, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 3.40%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by the Partnership and all of its subsidiaries (excluding the borrower subsidiary)(the "Guarantor Subsidiaries"). The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. There are no significant restrictions on the ability of the borrower 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 subsidiaries' assets.

The Credit Facility requires us to maintain (1) 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, (2) a maximum leverage ratio (consolidated indebtedness to adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses, both as defined in the Credit Facility), measured as of the last day of each fiscal quarter, of 3.50 to 1.00 and (3) a maximum first lien leverage ratio (consolidated secured indebtedness to adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses, both as defined in the Credit Facility), measured as of the last day of each fiscal quarter, of 2.50 to 1.00.

The Credit Facility also contains 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, weekly cash balance reports, 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. In addition, the Credit Facility contains certain anti-cash hoarding provisions, including the requirement to repay outstanding loans and cash collateralize outstanding letters of credit on a weekly basis in the amount of any cash on the balance sheet (subject to certain exceptions) in excess of $25 million.

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

As of December 31, 2020, 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 Second Lien Facility and the proceeds were used to fund a significant acquisition and related fees and expenses. Amounts under the Second Lien Facility were borrowed at a price of 98% with an initial interest rate of8.34% resulting in an effective interest rate of9.89%. As illustrated in the table above, the OID and issue costs of the Second Lien Facility are presented as reductions to the outstanding term loan. These costs are subject to amortization using the interest method over the term of the Second Lien Facility.

On November 2, 2020, we entered into the Second Lien Amendment which became effective upon the closing of the Juniper Transactions. In addition to a required prepayment of $50.0 million of outstanding advances under the Second Lien Facility, the Second Lien Amendment provides for (i) the extension of the maturity date of the Second Lien Facility to September 29, 2024, (ii) an increase to the margin applicable to advances under the Second Lien Facility; (iii) the imposition of certain limitations on capital expenditures, acquisitions and investments if the Asset Coverage Ratio (as defined therein) at the end of any fiscal quarter is less than 1.25 to 1.00, (iv) the requirement for maximum and, in certain circumstances as described therein, minimum hedging arrangements, (v) beginning in 2021, a requirement to make quarterly amortization payments equal to $1.875 million and (vi) a provision for the replacement of the LIBOR interest rate upon its expiration in 2022. On the Closing Date, we entered into the Omnibus Amendment to the Second Lien Facility (the “Omnibus Amendment”) to, among other things, effectuate the release of the Company from its guarantee of the obligations under the Second Lien Facility and its grant of a security interest in its assets. In January 2021, we incurred and capitalized $1.4 million of issue costs in connection with the Second Lien Amendment and wrote off $1.3 million of previously capitalized issue costs and OID allocable to the $50.0 million prepayment and a $1.3 million principal payment to liquidate the outstanding advances attributable to a single participant lender.

The outstanding borrowings under the Second Lien Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin of 8.25% or (b) a Eurodollar rate, including LIBOR through 2021, with a floor of1.00%, plus an applicable margin of 7.25%; provided that the applicable margin will increase to 9.25% and 8.25%, respectively, during any quarter in which the quarterly amortization payment is not made. As of December 31, 2020, the actual interest rate of outstanding borrowings under the Second Lien Facility was 8.00%. 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 Eurodollar borrowings is payable every one or 3 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 Eurodollar loans): from January 15, 2021 through January 14, 2022, 102% of the amount being prepaid, from January 15, 2022 through January 14, 2023, 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: from January 15, 2021 through January 14, 2022, 102% of the amount being prepaid, from January 15, 2023 through January 14, 2023, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of the Partnership'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 the Partnership and the Subsidiary Guarantors.

The Second Lien Facility has no financial covenants, but contains 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), limitations on capital expenditures, investments, 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, 2020, 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.

10. Income Taxes

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

	Year Ended December 31, 2020	2019	2018
Current income taxes (benefit)			
Federal	$ (1,236)	$ (1,236)	$ (2,471)
State	357	—	—
	(879)	(1,236)	(2,471)
Deferred income taxes (benefit)			
Federal	1,236	1,236	2,471
State	(2,660)	2,137	523
	(1,424)	3,373	2,994
	$ (2,303)	$ 2,137	$ 523

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

	Year Ended December 31, 2020		2019		2018	
Computed at federal statutory rate	$ (65,701)	(21.0)%	$ 15,272	21.0 %	$ 47,315	21.0 %
State income taxes, net of federal income tax benefit	(1,856)	(0.6)%	1,494	2.1 %	1,743	0.8 %
Change in valuation allowance	64,062	20.5 %	(14,240)	(19.6)%	(48,820)	(21.7)%
Other, net	1,192	0.4 %	(389)	(0.5)%	285	0.1 %
	$ (2,303)	(0.7)%	$ 2,137	3.0 %	$ 523	0.2 %

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

	December 31, 2020	December 31, 2019
Deferred tax assets:		
Net operating loss ("NOL") carryforwards	$ 180,531	$ 175,221
Alternative minimum tax ("AMT") credit carryforwards	—	1,236
Asset retirement obligations	1,188	1,073
Pension and postretirement benefits	301	340
Share-based compensation	467	880
Fair value of derivative instruments	2,737	4,191
Interest expense limitation	—	11,463
ROU assets	564	—
Other	1,484	2,441
	187,272	196,845
Less: Valuation allowance	(179,006)	(114,939)
Total net deferred tax assets	8,266	81,906
Deferred tax liabilities:		
Property and equipment	7,728	83,330
ROU obligations	538	—
Total deferred tax liabilities	8,266	83,330
Net deferred tax liabilities	$ —	$ (1,424)

Income Tax Provision

The provision for the years ended December 31, 2020, 2019 and 2018 includes current federal benefits of $1.2 million, $1.2 million and $2.5 million attributable to refunds of AMT credits for the 2020, 2019 and 2018 tax years, respectively. The amounts attributable to 2020 combined the amounts attributable to 2019, which had been recognized on our Consolidated Balance Sheet as of December 31, 2019 as a current asset, were received in 2020 as an acceleration of all AMT credits in connection with certain provisions of the CARES Act. The $2.5 million attributable to 2018 was refunded to us in 2019. These benefits have been offset by corresponding decreases in the deferred tax asset associated with AMT credit carryforwards giving rise to deferred federal expenses for the years ended December 31, 2020, 2019 and 2018, respectively. In addition, we have recognized deferred state tax benefits of $2.7 million and expenses of $2.1 million and $0.5 million attributable to property and equipment as well as $0.4 million of current state expense attributable to the Texas margin tax for the year ended December 31, 2020 for overall effective tax rates of 0.7%, 3.0% and 0.2% for the years ended December 31, 2020, 2019 and 2018, respectively.

Deferred Tax Assets and Liabilities

As of December 31, 2020, we had federal NOL carryforwards of approximately $638.6 million, a substantial portion of which, if not utilized, expire between 2032 and 2037. NOLs incurred after January 1, 2018 can be carried forward indefinitely. Because of the change in ownership provisions of the Code, use of a portion of our federal NOLs may be limited in future periods. As of December 31, 2020, we carried a valuation allowance against our federal and state deferred tax assets of $179.0 million. We considered both the positive and negative evidence in determining whether it was more likely than not that some portion or all of our deferred tax assets will be realized. The amount of deferred tax assets 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 is no longer present and additional weight is given to subjective positive evidence, including projections for growth. The valuation allowance along with $8.3 million of deferred tax liabilities fully offset our deferred tax assets. Accordingly, there are no net deferred tax assets or liabilities reflected on our Consolidated Balance Sheet as of December 31, 2020.

The net deferred tax liability recognized on the Consolidated Balance Sheet as of December 31, 2019 is attributable to certain state deferred tax liabilities associated with property and equipment in excess of federal deferred tax assets associated with refundable AMT credit carryforwards for tax years ending after 2019.

Other Income Tax Matters

We had no liability for unrecognized tax benefits as of December 31, 2020 and 2019. There were no interest and penalty charges recognized during the years ended December 31, 2020, 2019 and 2018. Tax years from 2015 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

11. Leases

We generally have lease arrangements for office facilities and certain office equipment, certain field equipment including compressors, drilling rigs, crude oil storage tank capacity, land easements and similar arrangements for rights-of-way, and certain gas gathering and gas lift assets. Our short-term leases included in the disclosures below are primarily comprised of our contractual arrangements with certain vendors for operated drilling rigs, crude oil storage tank capacity and our field compressors. Our primary variable lease was represented by our field gas gathering and gas lift agreement with a midstream service provider and the lease payments are charged on a volumetric basis at a contractual fixed rate.

The following table summarizes the components of our total lease cost, as determined in accordance with ASC Topic 842, for the periods presented:

	Year Ended December 31,	
	2020	2019
Operating lease cost	$ 979	$ 773
Short-term lease cost	23,721	36,202
Variable lease cost	21,932	23,762
Less: Amounts charged as drilling costs [1]	(20,708)	(33,354)
Total lease cost recognized in the Consolidated Statement of Operations [2]	$ 25,924	$ 27,383

[1] Represents the combined gross amounts paid and (i) capitalized as drilling costs for our working interest share and (ii) billed to joint interest partners for their working interest share for short-term leases of operated drilling rigs.

[2] Includes $11.2 million and $12.1 million recognized in GPT, $ 13.8 million and $14.5 million recognized in Lease operating expense ("LOE") and $ 1.0 million and $0.8 million recognized in G&A for the years ended December 31, 2020 and 2019, respectively.

Operating lease rental expense, as determined in accordance with prior GAAP was $2.7 million for the year ended December 31, 2018, related primarily to field equipment, office equipment and office leases. The substantial difference between operating lease rental expense disclosed in accordance with prior GAAP and that provided in the table above for 2020 and 2019, in accordance with ASC Topic 842, is attributable to the aforementioned field gas gathering and gas lift agreement which has been determined to be a variable lease under ASC Topic 842.

The following table summarizes supplemental cash flow information, as determined in accordance with ASC Topic 842, related to leases for the periods presented:

	Year Ended December 31,	
	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 943	$ 659
ROU assets obtained in exchange for operating lease obligations [1]	$ 388	$ 3,325

[1] Includes $2.5 million recognized upon adoption of ASC Topic 842 and $ 0.8 million obtained during the twelve months ended December 31, 2019.

The following table summarizes supplemental balance sheet information related to leases as of the dates presented:

	December 31,	
	2020	2019
ROU assets – operating leases	$ 2,432	$ 2,740
Current operating lease obligations	$ 936	$ 847
Noncurrent operating lease obligations	1,752	2,232
Total operating lease obligations	$ 2,688	$ 3,079
Weighted-average remaining lease term – operating leases	3.1 years	4.1 years
Weighted-average discount rate – operating leases	3.24 %	5.97 %
Maturities of operating lease obligations for the years ending December 31,		
2021	$ 936	
2022	874	
2023	872	
2024	146	
Total undiscounted lease payments	2,828	
Less: imputed interest	(140)	
Total operating lease obligations	$ 2,688	

12. Supplemental Balance Sheet Detail

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

	December 31,	
	2020	2019
Prepaid and other current assets:		
Tubular inventory and well materials	$ 3,856	$ 2,989
Prepaid expenses [1]	15,189	1,469
	$ 19,045	$ 4,458
Other assets:		
Deferred issuance costs of the Credit Facility, net of amortization	$ 2,349	$ 3,952
Right-of-use assets – operating leases	2,432	2,740
Other	127	32
	$ 4,908	$ 6,724
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 7,055	$ 30,098
Drilling costs	16,088	18,832
Royalties	26,615	44,537
Production, ad valorem and other taxes	3,094	3,244
Compensation and benefits	4,222	5,272
Interest	504	730
Current operating lease obligations	936	847
Other [2]	4,254	2,264
	$ 62,768	$ 105,824
Other liabilities:		
Asset retirement obligations	$ 5,461	$ 4,934
Noncurrent operating lease obligations	1,752	2,232
Defined benefit pension obligations	865	873
Postretirement health care benefit obligations	284	343
	$ 8,362	$ 8,382

[1] The balance as of December 31, 2020 includes $ 13.6 million for the prepayment of drilling and completion services and materials in advance of the program for the first quarter of 2021.
[2] The balance as of December 31, 2020 includes $ 3.5 million of accrued costs attributable to Juniper Transaction expenses.

13. Fair Value Measurements

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

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

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

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

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and our variable-rate Credit Facility and Second Lien Facility borrowings. As of December 31, 2020, the carrying value of all these financial instruments approximated fair value. Our derivatives are marked-to-market and presented at their fair values.

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:

	As of December 31, 2020			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Commodity derivative assets – current	$ 78,793	$ —	$ 78,793	$ —
Commodity derivative assets – noncurrent	$ 25,449	$ —	$ 25,449	$ —
Liabilities:				
Interest rate swap liabilities - current	$ (3,655)	$ —	$ (3,655)	$ —
Interest rate swap liabilities - noncurrent	$ (1,645)	$ —	$ (1,645)	$ —
Commodity derivative liabilities – current	$ (81,772)	$ —	$ (81,772)	$ —
Commodity derivative liabilities – noncurrent	$ (26,789)	$ —	$ (26,789)	$ —

	As of December 31, 2019			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Commodity derivative assets – current	$ 4,131	$ —	$ 4,131	$ —
Commodity derivative assets – noncurrent	2,750	—	2,750	—
Liabilities:				
Commodity derivative liabilities – current	$ (23,450)	$ —	$ (23,450)	$ —
Commodity derivative liabilities – noncurrent	(3,385)	—	(3,385)	—

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, 2020, 2019 and 2018.

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 using industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied volatilities, time value and non-performance risk. For the current market prices, we use third-party quoted forward prices, as applicable, for NYMEX WTI, MEH crude oil and NYMEX HH natural gas closing prices as of the end of the reporting periods. Each of these is a level 2 input.
- *Interest rate swaps*: We determine the fair values of our interest rate swaps using an income valuation approach valuation technique which discounts future cash flows back to a single present value. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each of these is a Level 2 input.

Non-Recurring Fair Value Measurements

In addition to the fair value measurements applied with respect to the Hunt Acquisition, as described in Note 4, the most significant non-recurring fair value measurements utilized in the preparation of our Consolidated Financial Statements are those attributable to the initial determination of AROs associated with the ongoing development of new oil and gas properties. The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial estimates as level 3 inputs.

14. Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2020, by category, for the next5 years and thereafter:

Year	Gathering and Intermediate Transportation	Other Commitments
2021	$ 12,962	$ 317
2022	12,962	184
2023	12,962	—
2024	12,962	—
2025	12,962	—
Thereafter	24,827	—
Total	$ 89,637	$ 501

Drilling and Completion Commitments

As of December 31, 2020, we had contractual commitments on a pad-to-pad basis fortwo drilling rigs. Additionally, we have an agreement, effective January 2, 2021, which can be terminated with 30 days' notice by either party, to utilize certain frac services and related materials, with no minimum commitment, through December 31, 2021.

Gathering and Intermediate Transportation Commitments

We have long-term agreements with Nuevo G&T and Nuevo Dos Marketing, LLC ("Nuevo Marketing" and together with Nuevo G&T, collectively "Nuevo") to provide gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production in as well as volume capacity support for certain downstream interstate pipeline transportation.

Nuevo is obligated to gather and transport our crude oil and condensate from within a dedicated area in the Eagle Ford via a gathering system and intermediate takeaway pipeline connecting to a downstream interstate pipeline operated by a third party through 2041. We have a minimum volume commitment ("MVC") of 8,000 gross barrels of oil per day to Nuevo through 2031 under the gathering agreement.

Under a marketing agreement, we have a commitment to sell8,000 barrels per day of crude oil (gross) to Nuevo, or to any third party, utilizing Nuevo Marketing's capacity in a downstream interstate pipeline through 2026.

Under each of the agreements with Nuevo, credits for deliveries of volumes in excess of the volume commitment may be applied to any deficiency arising in the succeeding 12-month period.

Crude Oil Storage

As a component of the crude oil gathering agreement referenced above, we have access up to approximately180,000 barrels of dedicated tank capacity for no additional charge at the service provider's central delivery point facility ("CDP"), in Lavaca County, Texas through February 2041. We have also contracted for access up to an additional 70,000 barrels of tank capacity at the CDP on a month-to-month basis which can be terminated by either party with 45-days' notice to the counterparty. We have also contracted for crude oil storage capacity for up to 90,000 barrels with a downstream interstate pipeline at a facility in DeWitt County, Texas, on a month-to-month basis which can be terminated by either party with 45-days' notice to the counterparty. Finally, we have an agreement with a marketing affiliate of the aforementioned downstream interstate pipeline to utilize up to 62,000 barrels of capacity within their system on a firm basis and an additional120,000 barrels, if available, on a flexible basis through April 2021. Costs associated with these agreements are in the form of monthly fixed rate short-term leases and are charged as incurred on a monthly basis to GPT.

Other Commitments

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

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. As of December 31, 2020, we had an estimated reserve in the amount of $0.1 million for certain claims made against us regarding previously divested operations included in "Accounts payable and accrued liabilities."

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, 2020, we have recorded AROs of $5.5 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.

15. Shareholders' Equity

Preferred Stock

As of December 31, 2020 and December 31, 2019, there were 5,000,000 shares of preferred stock authorized with none issued or outstanding.

Common Stock

As of December 31, 2020 and December 31, 2019, there were 15,200,435 and 15,135,598 shares of Common Stock outstanding, respectively, with a par value of $0.01 per share. We have a total of 45,000,000 shares authorized. We have not paid any cash dividends on our common stock. In addition, our Credit Facility and Second Lien Facility have restrictive covenants that limit our ability to pay dividends.

Paid-in Capital

Represents the value of consideration we received in excess of par value for the original issuance of our common stock net of costs directly attributable to the issuance transactions. In addition, paid-in capital includes amounts attributable to the amortized cost of share-based awards that have been granted to our employees and directors, net of any adjustments with the ultimate vesting of such awards.

Accumulated Other Comprehensive Income (Loss)

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 approximately $0.1 million for all periods presented.

16. Share-Based Compensation and Other Benefit Plans

We reserved 1,424,600 shares of Common Stock for issuance under the Penn Virginia Corporation Management Incentive Plan (the "Incentive Plan") for future share-based compensation awards. A total of 641,997 time-vested restricted stock units ("RSUs") and258,991 performance restricted stock units ("PRSUs") have been granted as of December 31, 2020 including 57,500 RSUs and 57,500 PRSUs that were issued as an inducement award outside of the Incentive Plan.

We recognized $3.3 million, $4.1 million and $4.6 million of share-based compensation expense for the years ended December 31, 2020, 2019 and 2018, respectively. All of our 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.

Time-Vested Restricted Stock Units

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

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

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	136,876	$ 49.76
Granted	281,382	$ 4.49
Vested	(63,916)	$ 43.30
Forfeited	(35,062)	$ 27.83
Balance at end of year	319,280	$ 13.56

As of December 31, 2020, we had $3.0 million of unrecognized compensation cost attributable to RSUs. We expect that cost to be recognized over a weighted-average period of 1.0 years. The total grant-date fair values of RSUs that vested in 2020, 2019 and 2018 was $2.8 million, $3.0 million and $3.3 million, respectively.

Performance Restricted Stock Units

In the years ended December 31, 2020 and December 31, 2019, we granted145,399 and 15,066 PRSUs, respectively to members of our management. There were no PRSUs granted for the year ended December 31, 2018. The PRSUs were issued collectively in separate tranches with individual performance periods beginning in January 2019, 2020 and 2021, 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 or for those granted in 2019 and 2020, a peer group of companies. 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 $84.02 per PRSU for the 2019 grant and a range of $2.40 to $16.02 for the 2020 grants.

The ranges for the assumptions used in the Monte Carlo model for the PRSUs granted during 2020, 2019 and 2017 are presented as follows:

	2020	2019
Expected volatility	101.32% to 117.71%	49.9 %
Dividend yield	0.0%	0.0%
Risk-free interest rate	0.18% to 0.51%	1.66 %

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

	Performance Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	79,914	$ 52.73
Granted	145,399	$ 7.79
Vested	(31,146)	$ 58.35
Forfeited	(20,635)	$ 55.99
Balance at end of year	173,532	$ 13.68

As of December 31, 2020, we had $1.5 million of unrecognized compensation cost attributable to PRSUs. We expect that cost to be recognized over a weighted-average period of 1.3 years.

Executive Transition and Retirement

In August 2020, we appointed Darrin Henke our new president and chief executive officer, or CEO, and director following the retirement of John Brooks. We incurred incremental G&A costs of approximately $1.2 million, in connection with Mr. Henke's appointment and Mr. Brooks' separation. In addition to those incremental costs, we recognized $0.7 million during the year ended December 31, 2020 for the accelerated vesting of certain share-based compensation awards of Mr. Brooks in connection with his retirement.

In December 2019, Steven A. Hartman separated from the Company. In accordance with his separation and transition agreement ("Hartman Separation Agreement"), we recorded a charge of $0.5 million for severance and other cash benefits that were paid in the first quarter of 2020. The Hartman Separation Agreement also provided for the accelerated vesting of certain share-based compensation awards for which we recognized accelerated expense of $0.2 million during the year ended December 31, 2019. Effective February 28, 2018, Mr. Harry Quarls retired from his position as a director and Executive Chairman of the Company. In connection with his retirement, we entered into a separation and consulting agreement ("Quarls Separation Agreement") whereby Mr. Quarls agreed to provide transition and support services to us through December 31, 2018. We paid Mr. Quarls $0.3 million under the Quarls Separation Agreement. The Quarls Separation Agreement included a general release of claims and provided for the accelerated vesting of certain share-based compensation awards for which we recognized accelerated expense of $0.6 million during the year ended December 31, 2018. The costs associated with the Hartman and Quarls Separation Agreements, including the share-based compensation charges, were included as a component of "G&A expenses" in our Consolidated Statements of Operations for the years ended December 31, 2019 and 2018, respectively.

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 $0.9 million, $0.9 million, $0.6 million for the years ended December 31, 2020, 2019 and 2018, 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 $0.3 million are included in the "Accounts payable and accrued expenses" caption on our Consolidated Balance Sheets as of December 31, 2020 and 2019, respectively.

Defined Benefit Pension and Postretirement Health Care Plans

We maintain unqualified legacy defined benefit pension and defined benefit postretirement health care plans which cover a limited population of former employees that retired prior to January 1, 2000. The combined expense recognized with respect to these plans was less than $0.1 million for each year ended December 31, 2020, 2019 and 2018, and is included as a component of "Other, net" in our Statements of Operations. The combined unfunded benefit obligations under these plans were $1.3 million and are included within the "Accounts payable and accrued expenses" (current portion) and "Other liabilities" (noncurrent portion) captions on our Consolidated Balance Sheets as of December 31, 2020 and 2019.

17. Interest Expense

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

	Year Ended December 31,		
	2020	2019	2018
Interest on borrowings and related fees	$ 29,851	$ 36,593	$ 32,164
Accretion of original issue discount [1]	811	743	680
Amortization of debt issuance costs [2]	3,339	2,611	2,736
Capitalized interest	(2,744)	(4,136)	(9,118)
	$ 31,257	$ 35,811	$ 26,462

1 Includes accretion of original issue discount attributable to the Second Lien Facility (see Note 9).

2 The year ended December 31, 2020 includes a total of $ 0.9 million of accelerated amortization attributable to the reduction in the borrowing base associated with an amendment to the Credit Facility in the spring of 2020.

18. Earnings per Share

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

	Year Ended December 31,		
	2020	2019	2018
Net income (loss) – basic and diluted	$ (310,557)	$ 70,589	$ 224,785
Weighted-average shares – basic	15,176	15,110	15,059
Effect of dilutive securities [1]	—	16	233
Weighted-average shares – diluted	15,176	15,126	15,292

1 Represents a combination of unvested RSUs and PRSUs that are dilutive with the exception of December 31, 2019 at which time all of our unvested PRSUs were determined to be at a zero percent vesting level due to the relative performance of our common stock. For the year ended December 31, 2020, approximately 0.1 million potentially dilutive securities had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share.

Supplemental Quarterly Financial Information (Unaudited)

2020	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues [1]	$ 91,379	$ 45,482	$ 69,411	$ 66,996
Operating income (loss) [2]	$ 21,301	$ (52,465)	$ (230,604)	$ (107,407)
Net income (loss)	$ 163,094	$ (94,715)	$ (243,413)	$ (135,523)
Net income (loss) per share – basic [3]	$ 10.76	$ (6.24)	$ (16.03)	$ (8.92)
Net income (loss) per share – diluted [3]	$ 10.76	$ (6.24)	$ (16.03)	$ (8.92)
Weighted-average shares outstanding:				
Basic	15,152	15,167	15,183	15,200
Diluted	15,160	15,167	15,183	15,200

2019	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues [4]	$ 105,228	$ 122,767	$ 119,304	$ 123,917
Operating income	$ 38,668	$ 47,888	$ 40,040	$ 50,225
Net income (loss)	$ (38,697)	$ 51,625	$ 54,362	$ 3,299
Net income (loss) per share – basic [3]	$ (2.56)	$ 3.42	$ 3.60	$ 0.22
Net income (loss) per share – diluted [3]	$ (2.56)	$ 3.40	$ 3.59	$ 0.22
Weighted-average shares outstanding:				
Basic	15,098	15,106	15,110	15,126
Diluted	15,098	15,162	15,160	15,131

[1] Includes gains on sales of assets of less than $0.1 million for each quarter ended during 2020.
[2] Includes impairments of our oil and gas properties of $35.5 million, $236.0 million and $120.3 million during the quarters ended June 30, 2020, September 30, 2020 and December 31, 2020, respectively.
[3] The sum of the quarters may not equal the total of the respective year's earnings per common share due to changes in weighted-average shares outstanding throughout the year.
[4] Includes gains (losses) on sales of assets of less than $0.1 million, less than $0.1 million, less than $0.1 million and $(0.1) million during the quarters ended March 31, 2019, June 30, 2019, September 30, 2019 and December 31, 2019, respectively.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Oil and Gas Reserves

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

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

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

Proved Developed and Undeveloped Reserves	**Oil (MBbl)**	**NGLs (MBbl)**	**Natural Gas (MMcf)**	**Total Equivalents (MBOE)**
December 31, 2017	55,829	8,864	47,267	72,572
Revisions of previous estimates	(19,096)	(1,789)	(9,608)	(22,487)
Extensions and discoveries	48,119	11,737	59,447	69,764
Production	(6,077)	(1,004)	(5,181)	(7,944)
Purchase of reserves	11,278	969	5,827	13,218
Sale of reserves in place	(397)	(733)	(6,259)	(2,173)
December 31, 2018	89,656	18,044	91,493	122,950
Revisions of previous estimates	(24,709)	(4,055)	(25,440)	(33,006)
Extensions and discoveries	40,190	6,575	31,045	51,939
Production	(7,453)	(1,491)	(7,067)	(10,121)
Purchase of reserves	1,212	81	418	1,363
December 31, 2019	98,896	19,154	90,449	133,125
Revisions of previous estimates	(23,554)	(5,599)	(26,712)	(33,606)
Extensions and discoveries	29,966	3,208	15,357	35,734
Production	(6,829)	(1,165)	(5,360)	(8,887)
December 31, 2020	98,479	15,598	73,734	126,366
Proved Developed Reserves:				
December 31, 2018	35,190	6,279	31,833	46,774
December 31, 2019	40,641	8,846	41,808	56,455
December 31, 2020	36,360	7,979	37,597	50,605
Proved Undeveloped Reserves:				
December 31, 2018	54,466	11,765	59,660	76,176
December 31, 2019	58,255	10,308	48,641	76,670
December 31, 2020	62,119	7,619	36,137	75,761

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

Year Ended December 31, 2020

In 2020, our proved reserves declined by 6.8 MMBOE due primarily to lower commodity pricing reducing our reserves in excess of the positive revisions to replace production. In light of the ongoing COVID-19 pandemic and its impact on our capital resources, we undertook a substantial review of our drilling plans and available site inventory that resulted in a substantial shift in the focus of our near-term drilling schedule to a greater focus on our core, oilier prospects. This process resulted in an increase to extensions and discoveries of 35.7 MMBOE that was largely offset by 34.0 MMBOE of negative revisions due primarily to certain wells that are now beyond our five-year drilling window schedule. In addition, our revisions of previous estimates reflect: (i) 6.9 MMBOE of favorable revisions attributable to changes in lateral lengths and type curves, substantially offset by (ii) unfavorable revisions of 3.2 MMBOE due to performance and (iii) declines in pricing of 3.2 MMBOE.

Year Ended December 31, 2019

In 2019, our proved reserves increased by 10.2 MMBOE due primarily to substantial changes in our development plans from the southeast portion of our acreage position in the Eagle Ford to the central region. The overall shift to this region allows us to develop wells with a lower gas content than what we were experienced in the southeast region through the first half of 2019. After achieving more favorable results with certain wells in the central region, we proceeded to drill a total of 11 gross wells, or approximately 23 percent of our total wells drilled in 2019, in the central region that were not considered proved undeveloped locations at the end of 2018.

We had downward revisions of 33.0 MMBOE including: (i) 32.1 MMBOE due to a change in timing beyond five years attributable to our development plans as discussed above, as well as a reduction of drilling rigs from three to two, combining certain wells into extended reach lateral locations and other reductions due to changes in the plan of development, (ii) 2.7 MMBOE due to 15 percent lower crude oil pricing from $65.56 per barrel to $55.67 per barrel and (iii) 1.6 MMBOE due to reductions in lateral length and net revenue interests partially offset by (iv) 3.4 MMBOE due to improved performance of certain proved undeveloped wells and proved undeveloped wells transferred to proved developed net of lower performance associated with certain existing proved developed wells including those reclassified to proved non-producing. Extensions and discoveries of 51.9 MMBOE are substantially attributable to geographical shift in our development plan, greater utilization of extended reach laterals, increasing the length of such laterals, higher estimated ultimate reserves (“EUR”) per lateral foot as well the addition of certain non-operated royalty wells. We acquired 1.4 MMBOE in connection with the acquisition of certain non-operating partners working interests in locations in which we are the operator.

Year Ended December 31, 2018

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

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

Capitalized Costs Relating to Oil and Gas Producing Activities

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

	December 31,		
	2020	2019	2016
Oil and gas properties:			
Proved	$ 1,545,910	$ 1,409,219	$ 1,037,993
Unproved	49,935	53,200	63,484
Total oil and gas properties	1,595,845	1,462,419	1,101,477
Other property and equipment	23,068	21,317	16,462
Total capitalized costs relating to oil and gas producing activities	1,618,913	1,483,736	1,117,939
Accumulated depreciation and depletion	(896,219)	(364,716)	(191,802)
Net capitalized costs relating to oil and gas producing activities [1]	$ 722,694	$ 1,119,020	$ 926,137

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

Costs Incurred in Certain Oil and Gas Activities

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

	Year Ended December 31,		
	2020	2019	2018
Development costs [1]	$ 126,739	$ 335,925	$ 416,037
Proved property acquisition costs [2]	—	6,051	86,514
Unproved property acquisition costs [3]	3,448	7,570	30,637
Exploration costs [4]	342	363	377
	$ 130,529	$ 349,909	$ 533,565

[1] Includes plugging and abandonment asset additions of $0.2 million, $0.3 million and $0.7 million and capitalized internal costs of $1.9 million, $3.6 million and $3.3 million for the years ended December 31, 2020, 2019 and 2018, respectively.

[2] Includes plugging and abandonment assets acquired of $0.1 million and $0.4 million in the years ended December 31, 2019 and 2018. Also includes capitalized internal costs of $0.2 million and $0.5 million for the years ended December 31, 2019 and 2018.

[3] Includes capitalized interest of $2.5 million, $4.1 million and $9.1 million for the years ended December 31, 2020, 2019 and 2018, respectively as well as unproved properties acquired in the Hunt Acquisition during the year ended December 31, 2018.

[4] Includes geological costs, geophysical costs (seismic) and delay rentals for all periods presented.

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 below 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
December 31, 2018	$ 65.56	$ 23.60	$ 3.10
December 31, 2019	$ 55.67	$ 13.36	$ 2.58
December 31, 2020	$ 39.54	$ 7.51	$ 1.99

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,		
	2020	2019	2018
Future cash inflows	$ 3,832,194	$ 6,260,292	$ 6,719,145
Future production costs	(1,356,505)	(1,792,891)	(1,852,168)
Future development costs	(926,904)	(1,174,215)	(1,208,815)
Future net cash flows before income tax	1,548,785	3,293,186	3,658,162
Future income tax expense	(60,598)	(334,451)	(413,137)
Future net cash flows	1,488,187	2,958,735	3,245,025
10% annual discount for estimated timing of cash flows	(837,897)	(1,469,853)	(1,621,135)
Standardized measure of discounted future net cash flows	$ 650,290	$ 1,488,882	$ 1,623,890

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,		
	2020	2019	2018
Sales of oil and gas, net of production costs	$ (194,660)	$ (374,694)	$ (361,478)
Net changes in prices and production costs	(950,201)	(402,616)	585,737
Changes in future development costs	450,286	415,193	206,901
Extensions and discoveries	74,830	459,501	809,880
Development costs incurred during the period	102,459	253,982	204,160
Revisions of previous quantity estimates	(303,219)	(515,345)	(483,091)
Purchases of reserves-in-place	—	12,241	86,128
Sale of reserves-in-place	—	—	(8,912)
Changes in production rates and all other	(282,055)	(194,453)	60,160
Accretion of discount	160,010	176,935	60,897
Net change in income taxes	103,958	34,248	(126,976)
Net increase (decrease)	(838,592)	(135,008)	1,033,406
Beginning of year	1,488,882	1,623,890	590,484
End of year	$ 650,290	$ 1,488,882	$ 1,623,890

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, 2020. 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, 2020, 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, 2020. 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, 2020, 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, 2020, 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

(1) Financial Statements

The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 66 of this Annual Report on Form 10-K.

(2) Exhibits

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.

(2.1)	Contribution Agreement, dated as of November 2, 2020, by and among Penn Virginia Corporation, PV Energy Holdings, L.P. and JSTX Holdings, LLC (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on November 5, 2020).
(2.2)	Contribution Agreement, dated as of November 2, 2020, by and among Penn Virginia Corporation, PV Energy Holdings, L.P. and Rocky Creek Resources, LLC (incorporated by reference to Exhibit 2.2 to Registrant's Current Report on Form 8-K filed on November 5, 2020).
(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)	Articles of Amendment, dated as of January 14, 2021, to the 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 January 21, 2021).
(3.3)	Fifth Amended and Restated Bylaws of Penn Virginia Corporation, effective as of January 15, 2021 (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed on January 21, 2021).
(4.1)#	Description of Common Stock.
(10.1)	Master Agreement, Borrowing Base Increase Agreement, and Amendment No. 6 to Credit Agreement, dated as of May 7, 2019, among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 8, 2019).
(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)	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).
(10.8.1)	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).
(10.8.2)	Second Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of July 2, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.8.3)	Third Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of December 14, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P. (incorporated by reference to Exhibit 10.9.3 to Registrant's Annual Report on Form 10-K filed on February 27, 2019).
(10.9)	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).

(10.9.1) †	First Amendment to First Amended and Restated Crude Oil Marketing Agreement dated as of July 2, 2018 by and between Penn Virginia Oil & Gas, L.P. and Republic Midstream Marketing, LLC.(incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.10)*	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).
(10.10.1)*	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).
(10.10.2)*	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).
(10.10.3)*	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).
(10.11)*	Penn Virginia Corporation 2019 Management Incentive Plan (incorporated by reference to Appendix A to Company's Definitive Proxy Statement for its 2019 Annual General Meeting of Shareholders filed on July 1, 2019).
(10.11.1)*#	Form of Officer Restricted Stock Unit Award Agreement under 2019 Management Incentive Plan (incorporated by reference to Exhibit 10.11.2 to Registrant's Annual Report on Form 10-K filed on February 28, 2020).
(10.11.2)*#	Form of Performance Restricted Stock Unit Award Agreement under 2019 Management Incentive Plan (incorporated by reference to Exhibit 10.11.3 to Registrant's Annual Report on Form 10-K filed on February 28, 2020).
(10.11.3)*	Form of Director Restricted Stock Award Agreement under 2019 Management Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on September 6, 2019).
(10.12)*	Separation and Transition Agreement, entered into as of July 1, 2019, between Penn Virginia Corporation and Steven A. Hartman (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on July 8, 2019).
(10.13)*	Penn Virginia Corporation 2017 Special Severance Plan Amended and Restated Effective August 17, 2020 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on August 21, 2020).
(10.14)*#	Amendment No. 1 to the Penn Virginia Corporation 2017 Special Severance Plan dated as of December 23, 2020.
(10.15)	Form of Director Indemnification Agreement (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on October 11, 2016).
(10.16)*	Separation Agreement, dated as of August 17, 2020, by and between Penn Virginia Corporation and John A. Brooks (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on August 21, 2020).
(10.17)*	Form of Officer Indemnification Agreement (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on August 21, 2020).
(10.18)	Borrowing Base Redetermination Agreement and Amendment No. 7 to Credit Agreement, dated as of April 30, 2020, among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 6, 2020).
(10.19)	Agreement and Amendment No. 8 to Credit Agreement, dated as of July 8, 2020, among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent Agreement (incorporated by reference to Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q filed on November 6, 2020).
(10.20)	Agreement and Amendment No. 9 to Credit Agreement among Penn Virginia Holdings, LLC, as borrower, Penn Virginia Corporation, as parent, the subsidiaries of Penn Virginia Corporation party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent Creek (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on January 21, 2021).
(10.21)	Amendment No. 1 to Credit Agreement, dated as of November 2, 2020, by and among Penn Virginia Corporation, Penn Virginia Holding Corp. as borrower, the lenders from time to time party thereto and Jefferies Finance LLC, as administrative agent and collateral agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on November 5, 2020).
(10.22)	Omnibus Amendment among Penn Virginia Holdings, LLC, Penn Virginia Corporation, as parent, the subsidiaries of Penn Virginia Corporation party thereto, the lenders party thereto and Ares Capital Corporation, as administrative agent (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on January 21, 2021).
(10.23)	Amended and Restated Agreement of Limited Partnership, dated as of January 15, 2021, by and among PV Energy Holdings GP, LLC, Penn Virginia Corporation, JSTX Holdings, LLC and Rocky Creek Resources, LLC (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on January 21, 2021).
(10.24)	Investor and Registration Rights Agreement, dated January 15, 2021, by and among Penn Virginia Corporation, JSTX Holdings, LLC and Rocky Creek Resources, LLC (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on January 21, 2021).
(21.1)#	Subsidiaries of Penn Virginia Corporation.
(23.1)#	Consent of Grant Thornton LLP.

(23.2)#	Consent of DeGolyer and MacNaughton.
(31.1)#	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)#	Certification Pursuant to 18 Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1.1)††	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2)††	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(99.1)#	Report of DeGolyer and MacNaughton dated January 29, 2021 concerning evaluation of oil and gas reserves.
(101.INS)#	Inline XBRL Instance Document
(101.SCH)#	Inline XBRL Taxonomy Extension Schema Document
(101.CAL)#	Inline XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF)#	Inline XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB)#	Inline XBRL Taxonomy Extension Label Linkbase Document
(101.PRE)#	Inline XBRL Taxonomy Extension Presentation Linkbase Document
(104)#	The cover page of Penn Virginia Corporation's Annual Report on Form 10-K for the year ended December 31, 2020, formatted in Inline XBRL (included within the Exhibit 101 attachments).

* Management contract or compensatory plan or arrangement.
\# Filed herewith.
† Confidential treatment has been requested for this exhibit and confidential portions have been filed separately with the Securities and Exchange Commission.
†† Furnished herewith.

Item 16 Form 10-K Summary

None.

SIGNATURES

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

PENN VIRGINIA CORPORATION

March 9, 2021	By:	/s/ RUSSELL T KELLEY, JR. **Russell T Kelley, Jr.** **Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)**
March 9, 2021	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/ DARRIN J. HENKE **Darrin J. Henke**	President and Chief Executive Officer and Director (Principal Executive Officer)	March 9, 2021
/s/ RUSSELL T KELLEY, JR. **Russell T Kelley, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	March 9, 2021
/s/ TAMMY L. HINKLE **Tammy L. Hinkle**	Vice President and Controller (Principal Accounting Officer)	March 9, 2021
/s/ TIFFANY THOM CEPAK **Tiffany Thom Cepak**	Director	March 9, 2021
/s/ KEVIN CUMMING **Kevin Cumming**	Director	March 9, 2021
/s/ EDWARD GEISER **Edward Geiser**	Chairman of the Board	March 9, 2021
/s/ TIMOTHY W. GRAY **Timothy W. Gray**	Director	March 9, 2021
/s/ DARIN G. HOLDERNESS **Darin G. Holderness**	Director	March 9, 2021
/s/ TEMITOPE OGUNYOMI **Temitope Ogunyomi**	Director	March 9, 2021
/s/ JOSHUA SCHMIDT **Joshua Schmidt**	Director	March 9, 2021
Jeffrey Wojahn	Director	March 9, 2021

DESCRIPTION OF CAPITAL STOCK

The following summary of certain provisions of our capital stock does not purport to be complete and is subject to and is qualified in its entirety by our Second Amended and Restated Articles of Incorporation, as amended (our "Articles of Incorporation"), our Fifth Amended and Restated Bylaws (our "Bylaws") and the Investor and Registration Rights Agreement dated January 15, 2021. We urge you to read our Articles of Incorporation and our Bylaws, which are incorporated in this prospectus by reference as exhibits to the registration statement of which this prospectus forms a part, and by the applicable provisions of Virginia law.

As of February 26, 2021, our authorized capital stock was 50,000,000 shares. Those shares consisted of 5,000,000 authorized shares of preferred stock (par value $0.01 per share), of which 225,481.09 shares were outstanding as of February 26, 2021, and 45,000,000 authorized shares of common stock (par value $0.01 per share), of which 15,266,598 shares were outstanding as of February 26, 2021.

Our common stock is quoted on the Nasdaq Global Select Market under the symbol "PVAC."

Common Stock

Dividends

Subject to the rights of any series of preferred stock that we may issue, the holders of common stock may receive dividends when declared by the Board. Dividends may be paid in cash, in property or in shares of stock, or in any combination thereof.

Fully Paid

All outstanding shares of common stock are fully paid and non-assessable.

Voting Rights

Subject to the special voting rights of any preferred stock that we may issue, the holders of common stock may vote one vote for each share held together as a single class in the election of directors and on all other matters voted upon by our shareholders. Currently, the common stock and Series A preferred stock vote together as a single class in the election of directors and on all other matters voted upon by our shareholders. In uncontested elections, directors are elected by a majority of the votes cast in the election for such director nominee; in contested elections, directors are elected by a plurality of the votes cast in the election for such director nominee. Holders of common stock may not cumulate their votes in the elections of directors. The affirmative vote of more than two-thirds of our outstanding shares of common stock is required for amendments to our Articles of Incorporation, the approval of mergers, statutory share exchanges, certain sales or other dispositions of assets outside the usual and regular course of business, conversions, domestications and dissolutions. However, holders of our common stock are not entitled to vote on any amendment to our Articles of Incorporation that relates solely to the terms of any one or more series of preferred stock. The affirmative vote of at least 67% of our outstanding shares of common stock is required to amend the "Corporate Opportunity" provisions of our Articles of Incorporation. All other matters to be voted on by shareholders must be approved by a majority of the votes cast on the matter.

Liquidation Rights

If we dissolve our business, either voluntarily or not, holders of common stock will share equally in the assets remaining after we pay our creditors and preferred shareholders.

Other Rights

The holders of common stock have no preemptive rights to purchase our shares of common stock. Shares of common stock are not subject to any redemption or sinking fund provisions and are not convertible into any of our other securities.

Preferred Stock

The Board is authorized, without approval of shareholders, to issue one or more series of preferred stock. Subject to the provisions of our Articles of Incorporation and limitations prescribed by law, the Board may adopt an amendment to our Articles of Incorporation setting the number of shares of each series and the rights, preferences and limitations of each series, including the dividend rights, voting rights, conversion rights, redemption rights and any liquidation preferences of any wholly unissued series of preferred stock, the number of shares constituting each series and the terms and conditions of issue.

Undesignated preferred stock may enable the Board to render more difficult or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and to thereby protect the continuity of our management. The issuance of shares of preferred stock may adversely affect the rights of the holders of our common stock. For example, any preferred stock issued may rank prior to our common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights and may be convertible into shares of common stock. As a result, the issuance of shares of preferred stock may discourage bids for our common stock or may otherwise adversely affect the market price of our common stock or any existing preferred stock.

Series A Preferred Stock

On the Closing Date, we issued 225,481.09 shares of Series A preferred stock. Our Series A preferred stock may only be issued to and registered in the name of JSTX Holdings, LLC (“JSTX”), Rocky Creek Resources, LLC (“Rocky Creek”), their respective successors and permitted assigns (as governed by our Articles of Incorporation).

Each 1/100th of a share of our Series A preferred stock entitles the holder to one vote on all matters submitted to a vote of the holders of the Company’s common stock, as adjusted to account for any subdivision (by stock split, subdivision, exchange, stock dividend, reclassification, recapitalization or otherwise) or combination (by reverse stock split, exchange, reclassification, recapitalization or otherwise) or similar reclassification or recapitalization of the outstanding shares of the Company’s common stock into a greater or lesser number of shares.

Shares of our Series A preferred stock are non-economic interests in the Company, and no dividends can be declared or paid on the Series A preferred stock. In the event of any voluntary or involuntary liquidation, dissolution or winding up of the Company, after payment or provision for payment of the debts and other liabilities of the Company, the holder of our Series A preferred stock shall be entitled to receive, out of the assets of the Company or proceeds thereof available for distribution to shareholders of the Company, before any distribution of such assets or proceeds is made to or set aside for the holders of our common stock and any other stock of the Company ranking junior to our Series A preferred stock as to such distribution, payment in full in an amount equal to $0.01 per share of Series A preferred stock.

Our Series A preferred stock is not convertible into any other security of the Company. However, if a holder exchanges one common unit of the Partnership in exchange for one share of our common stock, it must also surrender to us 1/100th of a share of our Series A preferred stock for each common unit exchanged.

Anti-Takeover Provisions

Certain provisions in our Articles of Incorporation and our Bylaws, as well as certain provisions of Virginia law, may make more difficult or discourage a takeover of our business.

Certain Provisions of Our Articles of Incorporation and Our Bylaws

Shareholder Action by Unanimous Consent. Any action that could be taken by shareholders at a meeting may be taken, instead, without a meeting and without notice if a consent in writing is signed by all the shareholders entitled to vote on the action.

Blank Check Preferred Stock. Our Articles of Incorporation authorize the issuance of blank check preferred stock. As described above under "—Preferred Stock," the Board can set the voting rights, redemption rights, conversion rights and other rights relating to such preferred stock and could issue such stock in either private or public transactions. In some circumstances, the blank check preferred stock could be issued and have the effect of preventing a merger, tender offer or other takeover attempt that the Board opposes.

Vacancies in the Board. Subject to the rights of any preferred stock, any vacancy in the Board resulting from any death, resignation, retirement, disqualification, removal from office or newly created directorship resulting from an increase in the authorized number of directors or otherwise may be filled by majority vote of the remaining directors then in office, even if less than a quorum, or shareholders.

Special Meetings of Shareholders. Special meetings of shareholders may be called at any time and from time to time only upon the written request of the Board, the chairman of the Board or the holders of a majority of our outstanding common stock.

Advance Notice Requirements for Shareholder Director Nominations and Shareholder Business. Our Bylaws require that advance notice of shareholder director nominations and shareholder business for annual meetings be made in writing and given to our corporate secretary, together with certain specified information, not less than 90 days nor more than 120 days before the anniversary of the immediately preceding annual meeting of shareholders, subject to other timing requirements as specified in our Bylaws.

Virginia Anti-Takeover Statutes and Other Virginia Laws

Control Share Acquisitions Statute. Under the Virginia control share acquisitions statute, shares acquired in an acquisition that would cause an acquiror's voting strength to meet or exceed any of three thresholds (20%, 33 1/3% or 50%) have no voting rights unless (1) those rights are granted by a majority vote of all outstanding shares other than those held by the acquiror or any officer or employee director of the corporation or (2) the articles of incorporation or bylaws of the corporation provide that the provisions of the control share acquisitions statute do not apply to acquisitions of its shares. An acquiring person that owns five percent or more of the corporation's voting stock may require that a special meeting of the shareholders be held to consider the grant of voting rights to the shares acquired in the control share acquisition. This regulation was designed to deter certain takeovers of Virginia public corporations. Virginia law permits corporations to opt out of the control share acquisition statute. We have not opted out.

Affiliated Transactions. Under the Virginia anti-takeover law regulating affiliated transactions, material acquisition transactions between a Virginia corporation and any holder of more than 10% of any class of its outstanding voting shares are required to be approved by the holders of at least two-thirds of the remaining voting shares. Affiliated transactions subject to this approval requirement include mergers, share exchanges, material dispositions of corporate assets not in the ordinary course of business, any dissolution of the corporation proposed by or on behalf of a 10% holder or any reclassification, including reverse stock splits, recapitalization or merger of the corporation with its subsidiaries, that increases the percentage of voting shares owned beneficially by a 10% holder by more than five percent. For three years following the time that a shareholder becomes an interested shareholder, a Virginia corporation cannot engage in an affiliated transaction with the interested shareholder without approval of two-thirds of the disinterested voting shares and a majority of the disinterested directors. A disinterested director is a director who was a director on the date on which an interested shareholder became an interested shareholder or was recommended for election or elected by a majority of the disinterested directors then on the board. After three years, the approval of the disinterested directors is no longer required. The provisions of this statute do not apply if a majority of disinterested directors approve the acquisition of shares making a person an interested shareholder. As permitted by Virginia law, we have opted out of the affiliated transactions provisions.

Director Standards of Conduct

Under Virginia law, directors must discharge their duties in accordance with their good faith business judgment of the best interests of the corporation. Directors may rely on the advice or acts of others, including officers, employees, attorneys, accountants and board committees if they have a good faith belief in their competence. Virginia law provides that, in determining the best interests of the corporation, a director may consider the possibility that those interests may best be served by the continued independence of the corporation.

AMENDMENT TO THE

PENN VIRGINIA CORPORATION 2017 SPECIAL SEVERANCE PLAN

(As Amended and Restated Effective August 17, 2020)

WHEREAS, Penn Virginia Corporation (the "Company") maintains the Penn Virginia Corporation 2017 Special Severance Plan (as the same may be amended from time to time, the "Plan") for the benefit of its employees;

WHEREAS, pursuant to Section 10 of the Plan, prior to the Closing (as defined in the Plan), the Compensation & Benefits Committee of the Board of Directors of the Company (the "Committee") may amend or terminate the Plan at any time, without notice, and for any or no reason; provided, however, that any amendment or termination that is materially adverse to a Participant who has executed a Participation Agreement will not be effective as to such Participant in the event that a Closing occurs within twelve months thereafter, unless such action is approved in writing by such Participant;

WHEREAS, the Company has determined that it is in the best interests of the Company to amend the Plan to revise the definition of "Good Reason," in order to provide for the Company's right to cure for any Participants who have not executed a Participation Agreement.

NOW, THEREFORE, pursuant to its authority under Section 10 of the Plan, the Company hereby amends the Plan as follows, effective as of December 23, 2020:

1. Section 3(k) of the Plan is hereby amended and restated in its entirety to read as follows:

(k) "**Good Reason**" has the meaning ascribed to such term in any employment agreement between the Participant and the Company or, if none, means the occurrence of any of the following events or conditions: (i) a material reduction in the Participant's base salary or annual cash incentive compensation opportunity from that in effect immediately prior to the Closing; (ii) the relocation of the Participant to a location more than fifty (50) miles from the location at which the Participant is based immediately prior to the Closing or (iii) a material diminution in the Participant's title, authority, duties or responsibilities from those in effect as of immediately prior to the Closing; provided, however, Good Reason shall not have occurred unless (1) such event or condition remains uncured forty-five (45) days following Participant's delivery to the Company of written notice of the specific grounds for Good Reason (the "Cure Period"), (ii) such written notice is delivered within forty-five (45) days following the initial occurrence of the event or condition giving rise to Good Reason, and (iii) the Participant terminates his or her employment with the Company within ten (10) days after the expiration of the Cure Period.

IN WITNESS WHEREOF, Penn Virginia Corporation has caused this instrument to be signed by its duly authorized officer as of this 23rd day of December, 2020.

PENN VIRGINIA CORPORATION

By:/s/ Katherine Ryan

Its: Vice President, Chief Legal Counsel

Exhibit 21.1

Subsidiaries of Penn Virginia Corporation

Name	Jurisdiction of Organization
Penn Virginia Holdings, LLC	Delaware
PV Energy Holdings GP, LLC	Delaware
PV Energy Holdings, L.P.	Delaware
Penn Virginia Oil & Gas, LLC	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, LLC	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, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 9, 2021, 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, 2020. We consent to the incorporation by reference of said reports in the Registration Statements of Penn Virginia Corporation on Forms S-3 (File No. 333-238137 and File No. 333-214709) and Forms S-8 (File No. 333-252026, File No. 333-248403, File No. 333-213979 and File No. 333-233364).

/s/ GRANT THORNTON LLP

Houston, Texas
March 9, 2021

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 9, 2021

Penn Virginia Corporation
16285 Park Ten Place, Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our report entitled "Report as of December 31, 2020 on Reserves and Revenue of Certain Properties with interests attributable to Penn Virginia Corporation" (our Report) in Part I and in the "Notes to Consolidated Financial Statements" portions of the Annual Report on Form 10-K of Penn Virginia Corporation for the year ended December 31, 2020 (the Annual Report), to be filed with the United States Securities and Exchange Commission on or about March 9, 2021. In addition, we hereby consent to the incorporation by reference of our report of third party dated January 29, 2021, 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. 333-2238137 and 333-214709) and Form S-8 (File Nos. 333-252026, 333-248403, 333-213979, and 333-233364).

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Darrin J. Henke, President and 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 9, 2021

/s/ DARRIN J. HENKE

Darrin J. Henke
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Russell T Kelley, Jr., Senior Vice President, Chief Financial Officer and Treasurer 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 9, 2021

/s/ RUSSELL T KELLEY, JR

Russell T Kelley, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

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

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Darrin J. Henke, President and 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 9, 2021

/s/ DARRIN J. HENKE

Darrin J. Henke
President and 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, 2020, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Russell T Kelley, Jr., Senior Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

Date: March 9, 2021

/s/ RUSSELL T KELLEY, JR.

Russell T Kelley, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

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

DeGolyer and MacNaughton
5001 Spring Valley Road Suite 800 East
Dallas, Texas 75244
January 29, 2021

Penn Virginia Corporation
16285 Park Ten Place
Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2020, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Penn Virginia Corporation (Penn Virginia) has represented it holds an interest. This evaluation was completed on January 29, 2021. The properties evaluated herein consist of working and royalty interests located in Texas. Penn Virginia has represented that these properties account for 100 percent on a net equivalent barrel basis of Penn Virginia's net proved reserves as of December 31, 2020. 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 United States Securities and Exchange Commission (SEC). 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, 2020. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Penn Virginia after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, compression charges, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Penn Virginia to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Penn Virginia, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a nominal discount 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.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Penn Virginia and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Penn Virginia with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves - Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves - Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Penn Virginia, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Penn Virginia.

Penn Virginia has represented that its senior management is committed to the development plan provided by Penn Virginia and that Penn Virginia has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. 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. These analyses were 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 effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Penn Virginia from wells drilled through December 31, 2020, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through October 2020. Estimated cumulative production, as of December 31, 2020, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 2 months.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Penn Virginia, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Penn Virginia. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Penn Virginia has represented that the oil, condensate, and NGL prices were based on West Texas Intermediate (WTI) pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Penn Virginia to the reference price of $39.54 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $36.36 per barrel of oil and condensate and $7.51 per barrel of NGL.

Gas Prices

Penn Virginia has represented that the gas prices were based on Henry Hub pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The gas prices were calculated for each property using differentials furnished by Penn Virginia to the reference price of $1.985 per million Btu and held constant thereafter. Btu factors provided by Penn Virginia were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $1.822 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates Texas. Ad valorem taxes were calculated using rates provided by Penn Virginia based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Penn Virginia and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2020 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 wells, and reclamation and restoration associated with the abandonment, were provided by Penn Virginia and were not adjusted for inflation. At the request of Penn Virginia, abandonment costs and any associated negative future net revenue have been included herein for those proved developed properties for which reserves were estimated to be zero. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, 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 FASB 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 SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2020, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized in the following table, 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, 2020			
	Oil and Condensate (Mbbl)	NGL (Mbbl)	Sales Gas (MMcf)	Oil Equivalent (Mboe)
Proved Developed	36,360	7,979	37,597	50,605
Proved Undeveloped	62,119	7,619	36,137	75,761
Total Proved	**98,479**	**15,598**	**73,734**	**126,366**

Note: Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2020, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	Total Proved (M$)
Future Gross Revenue	1,450,464	3,832,194
Production and Ad Valorem Taxes	91,146	238,304
Operating Expenses	537,716	1,118,201
Capital and Abandonment Costs	28,771	926,904
Future Net Revenue	792,831	1,548,785
Present Worth at 10 Percent	485,062	657,546

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, 2020, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Penn Virginia. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Penn Virginia. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGOLYER and MacNAUGHTON

DeGOLYER and MacNAUGHTON Texas Registered Engineering Firm F-716

/s/ Dilhan Ilk, P.E.

Dilhan Ilk, P.E.

Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Dilhan Ilk, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Penn Virginia dated January 29, 2021, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 10 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Dilhan Ilk,, P.E.

Dilhan Ilk, P.E.

Senior Vice President
DeGolyer and MacNaughton