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 001-37419

PDC ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**95-2636730**
(State of incorporation)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: **(303) 860-5800**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Ticker Symbol	Name of each exchange on which registered
Common Stock, par value $0.01 per share	PDCE	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 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 our common stock held by non-affiliates on June 30, 2020 was $1.2 billion (based on the closing price of $12.44 per share as of the last business day of the fiscal quarter ending June 30, 2020).

As of February 16, 2021, there were 99,781,332 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

We hereby incorporate by reference into this document the information required by Part III of this Form, which will appear in our definitive proxy statement filed pursuant to Regulation 14A for our 2021 Annual Meeting of Stockholders.

PDC ENERGY, INC.
2020 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

Unless the context otherwise requires, references in this report to "PDC," the "Company," "we," "us," "our" or "ours" refer to the registrant, PDC Energy, Inc. and our wholly-owned subsidiaries consolidated for the purposes of our financial statements.

GLOSSARY OF UNITS OF MEASUREMENTS AND INDUSTRY TERMS

Units of measurements and industry terms are defined in the Glossary of Units of Measurements and Industry Terms, included at the end of this report.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") and the United States ("U.S.") Private Securities Litigation Reform Act of 1995 regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical fact included in and incorporated by reference into this report are "forward-looking statements." Words such as expect, anticipate, intend, plan, believe, seek, estimate, schedule and similar expressions or variations of such words are intended to identify forward-looking statements herein. Forward-looking statements include, among other things, statements regarding future: production, costs and cash flows; impacts of Colorado political matters, including recent rulemaking initiatives, given our geographic concentration; drilling locations, zones and growth opportunities; commodity prices and differentials; capital expenditures and projects, including the number of rigs employed; cash flows from operations relative to future capital investments; financial ratios and compliance with covenants in our revolving credit facility and other debt instruments; impacts of certain accounting and tax changes; ability to meet our volume commitments to midstream providers and timing and adequacy of midstream infrastructure; the potential return of capital to shareholders through buyback of shares and/or issuance of a dividend; ongoing compliance with our consent decree; risk of our counterparties non-performance on derivative instruments; and our ability to repay our 1.125% convertible notes due 2021 (the "2021 Convertible Notes") and fund planned activities.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this report or accompanying materials, we may use the term “projection” or similar terms or expressions, or indicate that we have “modeled” certain future scenarios. We typically use these terms to indicate our current thoughts on possible outcomes relating to our business or our industry in periods beyond the current fiscal year. Because such statements relate to events or conditions further in the future, they are subject to increased levels of uncertainty.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- the COVID-19 pandemic, including its effects on commodity prices, downstream capacity, employee health and safety, business continuity and regulatory matters;
- changes in global production volumes and demand, including economic conditions that might impact demand and prices for the products we produce;
- impact of political and regulatory developments in Colorado, particularly with respect to additional permit scrutiny;
- geopolitical factors, such as events that may reduce or increase production from particular oil-producing regions and/or from members of the Organization of Petroleum Exporting Countries;
- volatility of commodity prices for crude oil, natural gas and natural gas liquids ("NGLs") and the risk of an extended period of depressed prices, including risks relating to decreased revenue, income and cash flow, write-downs and impairments and availability of capital;
- volatility and widening of differentials;
- reductions in the borrowing base under our revolving credit facility;

- impact of governmental policies and/or regulations, including changes in environmental and other laws, the interpretation and enforcement of those laws and regulations, liabilities arising thereunder and the costs to comply with those laws and regulations;
- declines in the value of our crude oil, natural gas and NGLs properties resulting in impairments;
- changes in estimates of proved reserves;
- inaccuracy of reserve estimates and expected production rates;
- potential for production decline rates from our wells being greater than expected;
- timing and extent of our success in discovering, acquiring, developing and producing reserves;
- availability and cost of sufficient pipeline, gathering and other transportation facilities and related infrastructure to process and transport our production and the impact of these facilities and regional capacity on the prices we receive for our production;
- risks incidental to the drilling and operation of crude oil and natural gas wells;
- difficulties in integrating our operations and potential effects on capital requirements as a result of any significant acquisitions or acreage exchanges;
- increases in costs and expenses;
- limitations in the availability of supplies, materials, contractors and services that may delay the drilling or completion of our wells;
- potential losses of acreage due to lease expirations or otherwise;
- future cash flows, liquidity and financial condition;
- competition within the oil and gas industry;
- availability and cost of capital;
- success in marketing our crude oil, natural gas and NGLs;
- effect of crude oil and natural gas derivative activities;
- impact to our operations, personnel retention, strategy, stock price and expenses caused by the actions of activist shareholders;
- impact of environmental events, governmental and other third-party responses to such events and our ability to insure adequately against such events;
- cost of pending or future litigation;
- our ability to replace our oil and natural gas reserves;
- title defects in our oil and natural gas properties;
- civil unrest, terrorist attacks and cyber threats;
- our ability to retain or attract senior management and key technical employees; and
- success of strategic plans, expectations and objectives for our future operations.

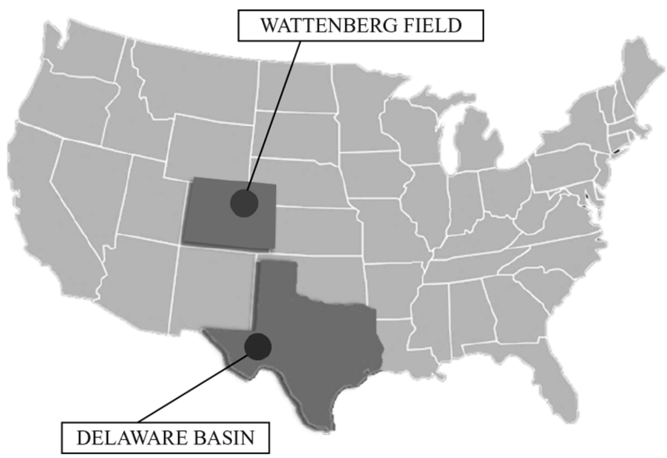
Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in this report and our other filings with the U.S. Securities and Exchange Commission ("SEC") for further information on risks and uncertainties that could affect our business, financial condition, results of operations and prospects, which are incorporated by this reference as though fully set forth herein. We caution you not to place undue reliance on the forward-looking statements, which speak only as of the date of this report. **We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.**

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

The Company

We are a domestic independent exploration and production company that acquires, explores and develops properties for the production of crude oil, natural gas and NGLs, with operations in the Wattenberg Field in Colorado and the Delaware Basin in west Texas. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays and our Delaware Basin operations are primarily focused in the horizontal Wolfcamp zones.

The following map presents the general locations of our development and production activities as of December 31, 2020:



The following table presents selected information regarding our results of operations for the periods presented:

	Year Ended/As of December 31, 2020	2019	Percent Change 2020-2019
	(production and reserves in MMBoe, dollars in millions)		
Wells:			
Gross productive wells	3,727	2,649	41 %
Net productive wells	2,841	2,101	35 %
Horizontal percentage	57 %	48 %	19 %
Gross operated wells turned-in-line	137	135	1 %
Net operated wells turned-in-line	129.5	125.0	4 %
Production:			
Wattenberg Field	57.5	38.0	51 %
Delaware Basin	10.8	11.4	(5)%
Total	68.4	49.4	38 %
Reserves:			
Proved reserves	731.1	610.9	20 %
Proved developed reserves percentage	44 %	35 %	26 %
Standardized measure	$ 3,282.2	$ 3,310.3	(1)%
PV-10 [(1)]	$ 3,454.6	$ 3,837.0	(10)%
Liquidity	$ 1,400	$ 1,291	8 %
Leverage ratio	1.7	1.4	21 %

(1) PV-10 is a non-U.S. GAAP financial measure. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure reported in accordance with U.S. generally accepted accounting principles ("U.S. GAAP"), but rather should be considered in addition to the standardized measure. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to the standardized measure included elsewhere in this report.

Significant 2020 Events

SRC Acquisition

In January 2020, we merged with SRC in a transaction valued at $1.7 billion, inclusive of SRC's net debt (the "SRC Acquisition"). Upon closing, we issued approximately 38.9 million shares of our common stock to SRC shareholders and holders of SRC equity awards, reflecting the issuance of 0.158 of a share of our common stock in exchange for each outstanding share of SRC common stock and the cancellation of outstanding SRC equity awards pursuant to the merger agreement that we entered into with SRC (the "Merger Agreement"). SRC's acreage was located on large, contiguous acreage blocks in the core Wattenberg Field. The acquisition added approximately 83,000 net acres to our asset portfolio.

In connection with the completion of the SRC Acquisition, we paid off and terminated SRC's revolving credit facility and we assumed $550.0 million aggregate principal amount of 6.25% senior notes due December 1, 2025 (the "SRC Senior Notes"). On January 17, 2020, we commenced an offer to repurchase the outstanding SRC Senior Notes at 101 percent of the principal amount. Upon expiration of the repurchase offer on February 18, 2020, holders of $447.7 million of the outstanding SRC Senior Notes accepted our redemption offer for a total redemption price of approximately $452.2 million, plus accrued and unpaid interest of $6.2 million. An aggregate principal amount of approximately $102.3 million of the SRC Senior Notes remains outstanding. We funded the aforementioned payment and termination of SRC's credit facility and repurchase of SRC Senior Notes with proceeds from our revolving credit facility.

Senior Notes Offering

In September 2020, we issued an additional $150.0 million principal amount of our 5.75% Senior Notes due in May 2026 (the "2026 Senior Notes"). The net proceeds from the offering were used to repay a portion of the amount outstanding under our revolving credit facility.

Business Strategy and Key Strengths

Our long-term business strategy focuses on creating shareholder value by: (i) delivering attractive returns from responsible development of our crude oil and natural gas properties; (ii) maintaining financial strength; (iii) generating sustainable cash flows from operations in excess of our capital investments in crude oil and natural gas properties; and (iv) returning capital to shareholders. Our key strengths create long-term shareholder value through the following:

- ***Strong financial position.*** We maintain a disciplined financial strategy that focuses on strong liquidity, low leverage ratios and an active commodity derivative program to help mitigate a portion of the risk associated with commodity price fluctuations. We believe that execution of this strategy will allow us to deliver strong corporate cash flows year-over-year, even through challenging commodity price environments. As of December 31, 2020, we had total liquidity of $1.4 billion, a leverage ratio, as defined in our revolving line of credit facility agreement, of 1.7x and commodity derivative positions covering approximately 14.2 MMBbls and 5.8 MMBbls of crude oil production for 2021 and 2022, respectively. As of the same date, we had hedged approximately 94,400 BBtu and 26,100 BBtu of natural gas production for 2021 and 2022, respectively.

- ***Focus on generating sustainable cash flows from operations in excess of capital investments.*** We are focused on generating multi-year sustainable cash flows from operations in excess of our capital investments through managing capital spending and growth rates, adjusting the timing of completion of our inventory of drilled uncompleted wells ("DUCs"), utilizing commodity derivative instruments, focusing on margin improvement from reductions in our cost structure and through increased capital efficiency from technological innovation. Our adjusted free cash flows, a non-GAAP measure, is used as a measure of our ability to return capital to shareholders, reduce debt levels and maintain strong liquidity. In 2020, we generated cash flows from operations of $870.1 million and adjusted free cash flows of $399.3 million.

- ***Absolute debt reduction, conservative total leverage targets and return of capital to shareholders.*** Through successful execution of our business plan, we meaningfully reduced our indebtedness to below $1.5 billion as of the date of this report. Consistent with our strategic goals, PDC reinstated its Stock Repurchase Program in late February 2021 and our board of directors recently approved a quarterly dividend program expected to commence mid-2021. PDC is positioned to focus on returning capital to shareholders and continued additional debt reductions, with a long-term target leverage ratio of 1.0x or below.

- ***Significant operational control in our core areas.*** We have, and expect to continue to have, a substantial degree of operational control over our properties. As a result of successfully executing our strategy of acquisitions and acreage trades in our core areas of operations, we have built multiple concentrated acreage positions with high working interests that we believe will allow us to enhance the value of our assets and replenish our drilling inventory. We currently operate approximately 77 percent of all the wells in which we have an interest. This operational control allows us to better manage our drilling, production, operating and administrative costs and to leverage our technical expertise in our core operating areas. Our leaseholds that are held by production further enhance our operational control by providing us with additional flexibility on the timing of drilling of those locations.

- ***Strong environmental, health and safety compliance programs and community outreach***. We have focused on establishing effective environmental, health and safety programs that are intended to promote safe working practices for our employees and contractors and to help earn the trust and respect of land owners, regulatory agencies and public officials. This is an important part of our strategy in effectively operating in today's intensive regulatory climate. We are also dedicated to being an active and contributing member of the communities in which we operate. We share our success with these communities in various ways, including charitable giving and community event sponsorships. We also strive to achieve continuous improvement in our corporate governance and have a demonstrated commitment to being responsive to investor input. In September of 2020, we released our inaugural Sustainability Report, which aligned with a formal Environmental, Social, and Governance ("ESG") reporting framework – Sustainability Accounting Standards Board – and increased transparency into our operations.

- ***Project inventory in two premier crude oil, natural gas and NGL plays.*** We have a substantial multi-year inventory of high-quality horizontal drilling opportunities across two premier U.S. onshore basins: the Wattenberg Field in Weld County, Colorado and the Delaware Basin in Reeves County, Texas. Our portfolio has a proven record of delivering strong and repeatable economic returns and provides us the ability to allocate capital investments and manage risk as each basin has its own operating and competitive dynamic in terms of commodity price markets, service costs, takeaway capacity and regulatory and political considerations. We have a disciplined development program that seeks to expand our project inventory through testing new intervals and considering various spacing configurations. We believe our project inventory will allow us to achieve attractive rates of return and grow our proved reserves and production in a sustainable fashion. Such expected returns on drilling can vary well by well and are based upon many factors, including but not limited to, commodity prices and well development and operating costs.

- ***Efficiency through technology and consolidation.*** Technological innovation has led to continued improvement in our drilling and completion times. We are utilizing technology to improve the efficiency of our horizontal drilling and completion operations in the Wattenberg Field. We continue to make progress towards improved capital efficiency through various drilling initiatives and completion designs in the Delaware Basin. The technology associated with our completions process continues to improve as we design wellbore placement and stage spacing and, in the Wattenberg Field, increase the completed lateral length of our wells. In addition, completion equipment, perforation clusters, fluid and sand type and concentration decisions continue to result in more efficient recoveries of crude oil and natural gas reserves. We continually optimize the expertise we have developed in the Wattenberg Field, to increase the efficiency of our Delaware Basin processes and procedures. Additionally, acreage consolidation, particularly in the Wattenberg Field, increases our ability to drill longer length lateral wells. Longer laterals allow us to develop our properties with a smaller number of wells and less truck traffic, with resulting benefits for our operations and for the communities in which we operate.

- ***Experienced management team with proven track record.*** We have a strong executive management team that has an average of 25 years of experience in the oil and gas industry. Collectively, this experience includes technical, operational, commercial, financial, legal and strategic aspects of the oil and gas industry. This team has a proven track record of executing value-added capital investment programs with a focus on financial discipline and improving on an already strong balance sheet, while growing production and proved reserves. Additionally, our team's experience has helped us continue to achieve our strategic objectives through periods of commodity price volatility, cost inflation and other challenging operating environments.

Operating Areas

Wattenberg Field. In the Wattenberg Field, we have identified a gross operated inventory of approximately 2,000 horizontal drilling locations that we expect to generate acceptable rates of return based on forward strip pricing, with an average lateral length of approximately 9,000 feet. Our inventory consists of approximately 200 gross operated DUCs, 300 approved permits, reflecting approximately 3.5 years of turn-in-line activity based on our current drilling plan, and 1,500 unpermitted locations. Our Wattenberg Field horizontal drilling locations have been substantially de-risked through multiple years of successful development in the field. We continue to analyze and test various wellbore spacing configurations in areas of the field that we believe have the potential to increase our gross operated inventory. Substantially all of our Wattenberg Field acreage is held by production. Wells in the Wattenberg Field typically have productive horizons at depths of approximately 6,500 to 7,500 feet below the surface. We continue to pursue various business development initiatives, with a focus on acreage exchanges or acquisitions, designed to increase our Wattenberg Field project inventory or to increase our ownership in our operated wells.

Delaware Basin. In the Delaware Basin, we have identified a gross operated economic inventory of approximately 115 horizontal drilling locations and 20 gross operated DUCs that we expect to generate acceptable rates of return based on forward strip pricing, targeting the Wolfcamp A and Wolfcamp B zones, within the oilier eastern and north central portions of our acreage. We continue to analyze and test various wellbore spacing configurations in areas of the field. Additionally, we have the possibility of adding inventory locations, outside of our target zones, in the future if the return on the wells meet our required economics. The average lateral length of these locations is approximately 8,900 feet. Wells in the Delaware Basin typically have productive horizons at depths of approximately 9,000 to 11,500 feet below the surface. We continue to pursue various business development initiatives, with a focus on acreage exchanges and joint development projects, designed to increase our Delaware Basin project inventory by establishing longer lateral drilling units capable of delivering attractive economic returns.

Oil and Gas Production and Operations

Proved Oil and Gas Reserves

The following table presents our proved reserve estimates as of December 31, 2020, 2019 and 2018:

	December 31, 2020	December 31, 2019	December 31, 2018
Proved reserves			
Crude oil and condensate *(MMBbls)*	212	197	190
Natural gas *(Bcf)*	1,901	1,558	1,336
NGLs *(MMBbls)*	203	154	132
Total proved reserves *(MMBoe)*	731	611	545
Proved developed reserves *(MMBoe)*	322	214	180
Standardized measure *(in millions)*	$ 3,282.2	$ 3,310.3	$ 4,447.7
Estimated undiscounted future net cash flows *(in millions)* (1)	$ 5,633.1	$ 5,895.9	$ 7,735.0
PV-10 (*in millions)* (2)	$ 3,454.6	$ 3,837.0	$ 5,321.3

(1) Amount represents aggregate undiscounted future net cash flows, before income taxes approximately $5.9 billion, $6.8 billion and $9.1 billion as of December 31, 2020, 2019 and 2018, respectively, less an internally-estimated undiscounted future income tax expense of approximately $0.3 billion, $0.9 billion and $1.4 billion, respectively.

(2) PV-10 is a non-U.S. GAAP financial measure. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure reported in accordance with U.S. GAAP, but rather should be considered in addition to the standardized measure. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to the standardized measure.

The additions to our proved reserves at December 31, 2020 as compared to December 31, 2019 were primarily due to the SRC Acquisition which were partially offset by downward revisions as a result of decreases in realized prices and revised drilling plans following the completion of the SRC Acquisition.

The following table presents our proved reserve estimates by category as of December 31, 2020:

	As of December 31, 2020				
Operating Region/Area	**Crude Oil and Condensate (MMBbls)**	**Natural Gas (Bcf)**	**NGLs (MMBbls)**	**Crude Oil Equivalent (MMBoe)**	**Percent**
Proved developed					
Wattenberg Field	69.1	752.3	80.9	275.5	38 %
Delaware Basin	17.2	108.6	10.8	46.0	6 %
Total proved developed	86.3	860.9	91.7	321.5	44 %
Proved undeveloped					
Wattenberg Field	105.7	958.8	102.7	368.1	50 %
Delaware Basin	19.7	81.5	8.1	41.5	6 %
Total proved undeveloped	125.4	1,040.3	110.8	409.6	56 %
Total proved reserves					
Wattenberg Field	174.8	1,711.1	183.6	643.6	88 %
Delaware Basin	36.9	190.1	18.9	87.5	12 %
Total proved reserves	211.7	1,901.2	202.5	731.1	100 %

Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Positive impacts of these variables and assumptions may result in a longer economic productive life of a property or the recognition of more economically viable proved undeveloped ("PUD") reserves, while negative impacts of these variables and assumptions may result in corresponding negative impacts. All of our proved reserves are located in the United States.

Commodity Pricing. Per SEC rules, the pricing used to prepare the proved reserves is based on the unweighted arithmetic average of the first of the month prices for the preceding 12 months. The NYMEX prices used in preparing the reserves are then adjusted based on energy content, location and basis differentials and other marketing deductions to arrive at the net realized price.

	Average Benchmark Prices		
December 31,	**Crude Oil (per Bbl) [1]**	**Natural Gas (per MMBtu) [1]**	**NGLs (per Bbl) [2]**
2020	$ 39.57	$ 1.99	$ 39.57
2019	55.69	2.58	55.69
2018	65.56	3.10	65.56

(1) Our benchmark prices for crude oil and natural gas are WTI and Henry Hub, respectively.
(2) For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.

The netted back price used to estimate our reserves, by commodity, are presented below.

	Price Used to Estimate Reserves [1]		
December 31,	**Crude Oil (per Bbl)**	**Natural Gas (per MMBtu)**	**NGLs (per Bbl)**
2020	$ 37.52	$ 1.26	$ 10.55
2019	52.63	1.50	12.21
2018	61.14	2.15	23.04

(1) These prices are based on the index prices and are net of basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the respective commodity.

Proved Reserves Sensitivity Analysis. We have performed an analysis of our proved reserve estimates as of December 31, 2020 to present sensitivity associated with a lower crude oil price as the value of crude oil influences the value of our proved reserves and PV-10 most significantly. Replacing the 2020 NYMEX price for crude oil used in estimating our reported proved reserves with $35.00 as shown on the table below, and leaving all other parameters unchanged, results in changes to our estimated proved reserves as shown.

	Pricing Scenario - NYMEX					
	Crude Oil (per Bbl)	**Natural Gas (per MMBtu)**	**Proved Reserves (MMBoe)**	**% Change from December 31, 2020 Estimated Reserves**	**PV-10 (in Millions)**	**PV-10 % Change from December 31, 2020 Estimated Reserves**
2020 SEC Reserve Report [1]	$ 39.57	$ 1.99	731.1	—	$ 3,454.6	—
Alternate Price Scenario	$ 35.00	$ 1.99	723.4	(1)%	$ 2,921.4	(15)%

(1) These prices are the SEC NYMEX prices applied to the calculation of the PV-10 value. Such prices have been applied consistently in the alternate pricing scenario to include the impact of adjusting for deductions for any basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the relevant commodity.

Commodities and Standardized Measure. Reserve estimates involve judgments and reserves cannot be measured exactly. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geologic and geophysical data and economic changes. Neither the estimated future net cash flows nor the standardized measure of discounted future net cash flows ("standardized measure") is intended to represent the current market value of our proved reserves.

For additional information regarding our standardized measures, as well as other information regarding our proved reserves, see Supplemental Information- Crude Oil and Natural Gas Properties included in *Item 8. Financial Statements and Supplementary Data* provided with our consolidated financial statements included elsewhere in this report.

Preparation of Reserve Estimates

Our proved reserves estimates as of December 31, 2020 were based on evaluations prepared by our independent petroleum engineering consulting firms, Ryder Scott Company, L.P. ("Ryder Scott") and Netherland, Sewell & Associates, Inc. ("NSAI") (collectively, our "external engineers"). Our proved reserve estimates were prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB").

Controls Over Reserve Report Preparation. Inputs and major assumptions related to our proved reserves are reviewed annually by an internal team composed of reservoir engineers, geologists, land and management for adherence to SEC guidelines through a detailed review of land and accounting records, available geological and reservoir data and production performance data. The internal team compiles the reviewed data and forwards the applicable data to our external engineers.

Annually, the Director of Reservoir Engineering & Technology reviews the reserves to ensure all the necessary significant inputs and steps are completed within our reserve process. After final approval from the Director of Reservoir Engineering & Technology, the results are presented to senior management and to our board of directors for their review.

Together, these internal controls are designed to promote a comprehensive, objective, and accurate reserves estimation process. As an additional confirmation of the reasonableness of our internal estimates, Ryder Scott and NSAI performed an independent evaluation of our estimated proved reserves in the Wattenberg Field and Delaware Basin, respectively, as of December 31, 2020.

When preparing our reserve estimates, our external engineers do not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, production volumes, well test data, historical costs of operations and development, product prices or any agreements relating to current and future operations of properties or sales of production. Our external engineers prepare estimates of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to ensure that the reserve estimates are complete, determined pursuant to acceptable industry methods and with a level of detail we deem appropriate. The final estimated reserve reports are prepared by our external engineers and reviewed by our engineering staff and management prior to issuance by those firms.

In determining our proved reserves estimates, we used a combination of performance methods, including decline curve analysis and other computational methods, offset analogies and seismic data and interpretation. All of our proved undeveloped reserves conform to the SEC five-year rule requirement as all proved undeveloped locations are scheduled, according to an adopted development plan, to be drilled within five years of the location's initial booking date.

Qualifications of Responsible Technical Persons. The professional qualifications of our lead engineer primarily responsible for overseeing the preparation of our reserve estimates, as defined in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information as promulgated by the Society of Petroleum Engineers, qualifies this individual as a Reserve Estimator. This person holds a Masters of Petroleum Engineering from the Colorado School of Mines and a Bachelors of Geology from the University of Colorado and has over 20 years of oil and gas experience.

Letters which identify the professional qualifications of the individuals at Ryder Scott and NSAI who are responsible for overseeing the preparation of our reserve estimates as of December 31, 2020 have been filed as Exhibits 99.1 and 99.2 to this report.

Production, Prices and Costs

Production and operating data for the years ended December 31, 2020, 2019 and 2018 was included in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* included elsewhere in this report.

Productive Wells

The following table presents our productive wells by operating area as of December 31, 2020:

	Crude Oil		Natural Gas		Total	
Operating Region/Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wattenberg Field	2,062	1,439.2	1,552	1,310.4	3,614	2,749.6
Delaware Basin	50	31.7	63	59.2	113	90.9
Total productive wells	2,112	1,470.9	1,615	1,369.6	3,727	2,840.5

Developed and Undeveloped Acreage

The following table presents our developed and undeveloped lease acreage as of December 31, 2020:

	Developed		Undeveloped		Total	
Operating Region/Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wattenberg Field	166,166	154,958	70,797	64,720	236,963	219,678
Delaware Basin	27,525	25,401	1,362	635	28,887	26,036
Total acreage	193,691	180,359	72,159	65,355	265,850	245,714

Developed lease acreage are acres spaced or assigned to productive wells and do not include undrilled acreage held by production under the terms of the lease. Large portions of the acreage that are considered developed under SEC guidelines are developed with vertical wells or horizontal wells that are in a single horizon. We believe much of this acreage has significant remaining development potential in one or more intervals with horizontal wells. Undeveloped acreage are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Substantially all of our undeveloped acreage in the Wattenberg Field and Delaware Basin are related to leaseholds that are held by production. Our Wattenberg Field leaseholds at risk to expire in 2021, 2022 and 2023 are not material. In the Delaware Basin, the majority of the drilling obligations or continuous drilling clauses associated with the asset have been met. Our Delaware Basin leaseholds at risk to expire in 2021, 2022 and 2023 are not material. See *Item 1A. Risk Factors - Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in substantial lease renewal costs or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.*

Drilling Results

The following tables set forth a summary of our developmental and exploratory well drilling results for the periods presented. Productive wells consist of wells that were turned-in-line and commenced production during the period, regardless of when drilling was initiated. In-process wells represent wells that are in the process of being drilled or have been drilled and are waiting to be fractured and/or for gas pipeline connection as of the date shown. We utilize pad drilling operations where multiple wells are developed from the same well pad in both the Wattenberg Field and Delaware Basin. Because we may operate multiple drilling rigs in each operating area, we expect to have in-process wells at any given time. Wells may be in-process for up two years.

Gross Development Well Drilling Activity

	Year Ended December 31,								
	2020			2019			2018		
Operating Region/Area	Productive (1)	In-Process (1)	Non-Productive	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive
Wattenberg Field, operated wells	124	214	—	114	145	—	139	133	—
Wattenberg Field, non-operated wells	27	48	—	12	41	—	20	5	—
Delaware Basin, operated wells	13	18	—	21	26	—	26	22	1
Delaware Basin, non-operated wells	—	—	—	9	—	—	11	—	—
Total gross development wells	164	280	—	156	212	—	196	160	1

(1) Amounts include 88 and seven gross in-process operated and non-operated development wells, respectively, received in the SRC Acquisition, of which a portion were completed during the period.

Net Development Well Drilling Activity

	Year Ended December 31,								
	2020			2019			2018		
Operating Region/Area	Productive (1)	In-Process (1)	Non-Productive	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive
Wattenberg Field, operated wells	116.5	201.8	—	105.1	135.0	—	126.8	122.4	—
Wattenberg Field, non-operated wells	0.9	3.5	—	1.1	3.7	—	2.5	0.9	—
Delaware Basin, operated wells	13.0	17.2	—	20.1	25.3	—	24.5	16.3	1.0
Delaware Basin, non-operated wells	—	—	—	1.3	—	—	1.2	—	—
Total net development wells	130.4	222.5	—	127.6	164.0	—	155.0	139.6	1.0

(1) Amounts include 80 and one net in-process operated and non-operated development wells, respectively, received in the SRC Acquisition, of which a portion were completed during the period.

Exploratory Well Drilling Activity

	Year Ended December 31,											
	2020				2019				2018			
	Productive		In-Process		Productive		In-Process		Productive		In-Process	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Delaware Basin	2	2.0	2	1.9	2	2.0	4	3.9	3	2.8	2	2.0

There were no exploratory drilling activities in the Wattenberg Field during 2020, 2019 and 2018.

Title to Properties

We believe that we hold good and defensible leasehold title to substantially all of our crude oil and natural gas properties, in accordance with standards generally accepted in the industry. A preliminary title examination is typically conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial curative work is performed, as necessary, with respect to discovered defects which we deem to be significant, in order to procure division order title opinions. Title examinations have been performed with respect to substantially all of our producing properties.

The properties we own are subject to royalty, overriding royalty and other outstanding interests. The properties may also be subject to additional burdens, liens or encumbrances customary in the industry, including items such as operating agreements, current taxes, development obligations under crude oil and natural gas leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with our use of the properties.

Substantially all of our crude oil and natural gas properties have been mortgaged or pledged as security for amounts borrowed under our revolving credit facility.

Offices

As of December 31, 2020, we leased corporate space in 1775 Sherman Street, Suite 3000, Denver, Colorado, where our corporate headquarters is located. We also maintain offices in Evans, Colorado and Midland, Texas. We anticipate closing on the sale of our office building we own in Bridgeport, West Virginia in the first half of 2021.

Significant Customers

We sell our crude oil and natural gas production to marketers and other purchasers which have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. The majority of our crude oil and natural gas production is transported through pipelines.

We made sales to four customers that each contributed to 10 percent or more of our 2020 total crude oil, natural gas and NGLs revenues. However, given the liquidity in the market for the sale of hydrocarbons, we believe that the loss of any single purchaser, or the aggregate loss of several purchasers, could be managed by selling to alternative purchasers.

Seasonality of Business

Weather conditions affect the demand for and prices of crude oil and natural gas. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of our annual results.

Delivery Commitments

Certain of our firm sales agreements for crude oil include delivery commitments. We believe our current production and reserves are sufficient to fulfill these delivery commitments. See *Note 12 - Commitments and Contingencies* in *Item 8. Financial Statements and Supplementary Data* for more information.

Governmental Regulation

The U.S. crude oil and natural gas industry is extensively regulated at the federal, state and local levels. The following is a summary of certain laws, rules and regulations currently in force that apply to us. The regulatory environment in which we operate changes frequently and we cannot predict the timing or nature of such changes or their effects on us.

Regulation of Crude Oil and Natural Gas Exploration and Production. Our exploration and production activities are subject to a variety of rules and regulations concerning drilling permits, location, spacing and density of wells, water discharge and disposal, prevention of waste, bonding requirements, surface use and restoration, public health and environmental protection and well plugging and abandonment. The primary state-level regulatory authority regarding these matters in Colorado is the Colorado Oil and Gas Conservation Commission ("COGCC") and in Texas is the Texas Railroad Commission.

Prior to preparing a surface location and commencing drilling operations on a well, we must procure permits and/or approvals for the various stages of the drilling process from the relevant state and local agencies. In addition, our operations must comply with rules governing the size of drilling and spacing units or proration units and the unitization or pooling of lands and leases. Some states, such as Colorado, allow the forced pooling or integration of tracts to facilitate exploration while other states, such as Texas, rely primarily or exclusively on voluntary pooling of lands and leases.

In states such as Texas where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore to drill and develop our leases in circumstances where we do not own all of the leases in the proposed unit. These risks also exist in Colorado, where a recent rule change has imposed new limits on forced pooling. State laws may also prohibit the venting or flaring of natural gas, which may impact rates of production of crude oil and natural gas from our wells. Leases covering state or federal lands often include additional laws, regulations and conditions which can limit the location, timing and number of wells we can drill and impose other requirements on our operations, all of which can increase our costs.

Regulation of Transportation of Commodities. We move natural gas through pipelines owned by other entities and sell natural gas to other entities that also utilize common carrier pipeline facilities. Natural gas pipeline interstate transmission and storage activities are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 ("NGA") and under the Natural Gas Policy Act of 1978 ("NGPA"). Rates and charges for the transportation of natural gas in interstate commerce, and the extension, enlargement or abandonment of jurisdictional facilities, among other things, are subject to regulation.

In addition, the Energy Policy Act of 2005 (the "EPAct 2005") prohibits “any entity” from using any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC. The EPAct 2005 provides FERC with substantial enforcement authority to prohibit such manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC Order 704 requires that any market participant, including natural gas producers, gatherers and marketers, that engaged in wholesale sales or purchases of natural gas that equaled or exceeded 2.2 MMBtus of physical natural gas in the previous calendar year to report to FERC the aggregate volumes of natural gas produced or sold at wholesale in such calendar year. Order 704 applies only to those transactions that utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the market participant to determine which individual transactions are to be reported under the guidance of Order 704. Additional information that must be reported includes whether the price in the relevant transaction was reported to any index publisher, and if so, whether such reporting complied with FERC’s policy statement on price reporting. To the extent that we engage in wholesale sales or purchases of natural gas that equal or exceed 2.2 MMBtus of physical natural gas in a calendar year pursuant to transactions utilizing, contributing or having the potential to contribute to the formation of price indices, we may be subject to the reporting requirements of Order 704.

Gathering is exempt from regulation under the NGA, thus allowing gatherers to charge negotiated rates. Gathering lines are, however, subject to state regulation, which includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and rate regulation on a complaint basis. We own certain pipeline facilities in the Delaware Basin that we believe are exempt from regulation under the NGA as “gathering facilities,” but which may in some cases be subject to state regulation.

Although FERC has set forth a general test to determine whether facilities are exempt from regulation under the NGA as “gathering” facilities, FERC’s determinations as to the classification of facilities are performed on a case-by-case basis. With respect to facilities owned by third parties and on which we move natural gas, to the extent that FERC subsequently issues an order reclassifying facilities previously thought to be subject to FERC jurisdiction as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of moving natural gas to the point of sale may be increased. Further, to the extent that FERC issues an order reclassifying facilities that we own that were previously thought to be non-jurisdictional gathering facilities as subject to FERC jurisdiction, we could be subject to additional regulatory requirements under the NGA and the NGPA.

Transportation and safety of natural gas is also subject to regulation by the U.S. Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), under the Natural Gas Pipeline Safety Act of 1968, as amended, which imposes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the "PIPES Act 2006"), and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the "PIPES Act 2011"). We own certain pipeline facilities in the Delaware Basin that are subject to such regulation by PHMSA.

In addition to natural gas, we move crude oil, condensate and natural gas liquids (collectively, "liquids") through pipelines owned by other entities and sell such liquids to other entities that also utilize pipeline facilities that may be subject to regulation by FERC. FERC regulates the rates and terms and conditions of service for the interstate transportation of liquids under the Interstate Commerce Act, as it existed on October 1, 1977 (the "ICA"), and the rules and regulations promulgated thereunder. This includes movements of liquids through any pipelines, including those located solely within one state, that are providing part of the continuous movement of such liquids in interstate commerce for a shipper. The ICA requires that pipelines providing jurisdictional movements maintain a tariff on file with FERC, setting forth established rates and the rules and regulations governing transportation service, which must be “just and reasonable.” The ICA also requires that services be provided in a manner that is not unduly discriminatory or unduly preferential; in some cases, this may result in the proration of capacity among shippers in an equitable manner.

The intrastate transportation of crude oil and NGLs is subject to regulation by state regulatory commissions, which in some cases require the provision of intrastate transportation on a nondiscriminatory basis and the prorationing of capacity on such pipelines under policies set forth in published tariffs. These state-level regulations may also impose certain limitations on the rates that the pipeline owner may charge for transportation.

Transportation of liquids by pipeline is subject to regulation by PHMSA pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as well as the PIPES Act 2006 and the PIPES Act 2011, which govern the design, installation, testing, construction, operation, replacement and management of liquids pipeline facilities. Liquids that are transported by rail may also be subject to additional regulation by PHMSA.

The availability, terms and cost of transportation affect the amounts we receive for our commodities. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen an increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in gas, which could adversely affect cash flows from the affected area.

Democratic control of the House, Senate and White House could lead to increased regulatory oversight and increased regulation and legislation, particularly around oil and gas development on federal lands, climate impacts and taxes.

Environmental Matters

Our operations are subject to numerous laws and regulations relating to environmental protection. These laws and regulations change frequently, and the effect of these changes is often to impose additional costs or other restrictions on our operations. We cannot predict the occurrence, timing, nature or effect of these changes. We also operate under a number of environmental permits and authorizations. The issuing agencies may take the position that some or all of these permits and authorizations are subject to modification, suspension, or revocation under certain circumstances, but any such action would have to comply with applicable procedures and requirements.

Hazardous Substances and Wastes

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have adopted requirements that limit the approved disposal methods for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations that are currently exempt from treatment as “hazardous wastes” may in the future be designated as hazardous wastes, and therefore may subject us to more rigorous and costly operating and disposal requirements. In April 2019, the EPA, pursuant to a consent decree between the EPA and a coalition of environmental groups and a related review of RCRA regulations, determined that revision of the regulations is not necessary. The EPA indicated that it will continue to work with states and other organizations to identify areas for continued improvement and to address emerging issues to ensure that exploration, development and production wastes continue to be managed in a manner that is protective of human health and the environment. Environmental groups, however, expressed dissatisfaction with the EPA’s decision and will likely continue to press the issue at the federal and state levels.

We currently own or lease numerous properties that have been used for the exploration and production of crude oil and natural gas for many years. If hydrocarbons or other wastes have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal by us or prior owners or operators of such properties, we could be subject to liability under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws, as well as state laws governing the management of crude oil and natural gas wastes. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of, transported or arranged for the disposal of the hazardous substances found at the site. Parties who are or were responsible for release of hazardous substances under CERCLA may be subject to full liability for the costs of cleaning up the hazardous substances that have been released into the environment or remediation to prevent future contamination and for damages to natural resources. In addition, under state laws, 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.

Hydraulic Fracturing

Hydraulic fracturing is commonly used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. We consistently utilize hydraulic fracturing in our crude oil and natural gas development programs. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations which are held open by the grains of sand, enabling the crude oil or natural gas to more easily flow to the wellbore. The process is generally subject to regulation by state oil and gas commissions, but is also the subject of various other regulatory initiatives at the federal, state and local levels.

Local Regulation

Various local and municipal bodies in each of the states in which we operate have sought to impose prohibitions, moratoria and other restrictions on hydraulic fracturing activities. In Colorado, Senate Bill 19-181 ("SB 19-181"), gives local governmental authorities increased authority to regulate the siting and surface impacts of oil and gas development. We primarily operate in the rural areas of the core Wattenberg Field in Weld County, a jurisdiction in which there has historically been significant support for the oil and gas industry. In Texas, legislation enacted in 2015 generally prohibits political subdivisions from banning, limiting or otherwise regulating oil and gas operations. See *Item 1A. Risk Factors-Risks Relating to Our Business and the Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.*

State Regulation

The states in which we currently operate have adopted or may adopt laws and regulations that impose or could impose, among other requirements, more stringent permitting processes and increased environmental protection and monitoring.

SB 19-181 changed the mission of the COGCC from fostering responsible and balanced development to regulating development to protect public health and the environment and directed the COGCC to undertake rulemaking on various operational matters. Pursuant to this direction, the COGCC conducted a series of rulemaking hearings during 2020 which resulted in updated regulatory and permitting requirements, including siting requirements. The COGCC commissioners determined that locations with residential or high occupancy building units within 2,000 feet would be subject to additional siting requirements, but also supported “off ramps” allowing oil and gas operators to site their drill pads as close as 500 feet from building units in certain circumstances. However, during the proceedings around SB 19-181, top Democratic leaders in the Colorado House and Senate, who served as authors and sponsors of the bill, made public statements indicating SB 19-181 was not intended to allow an outright ban on oil and gas development. At least one COGCC commissioner has publicly indicated his agreement with that interpretation.

In late July 2020, Governor Polis authored an op-ed stating that both industry and mainstream environmental groups have communicated a willingness to stand down on ballot initiatives in 2020, and to work together to prevent initiatives in 2022, while the regulatory process associated with SB 19-181 is in progress. As part of that agreement, Governor Polis stated that he would “actively oppose” ballot initiatives around the oil and gas industry and acknowledged the importance of regulatory certainty.

It is nevertheless possible that future ballot initiatives will be proposed that would dramatically limit the areas of the state in which drilling would be permitted to occur. See *Item 1A. Risk Factors-Risks Relating to Our Business and the Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.*

Federal Regulation

Beginning in 2012, the EPA implemented Clean Air Act ("CAA") standards (New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants) applicable to hydraulically fractured natural gas wells and certain storage vessels. The standards require, among other things, use of reduced emission completions, or "green" completions, to reduce volatile organic compound emissions during well completions as well as new controls applicable to a wide variety of storage tanks and other equipment, including compressors, controllers and dehydrators.

In February 2014, the EPA issued permitting guidance under the Safe Drinking Water Act ("SDWA") for the underground injection of liquids from hydraulically fractured and other wells where diesel is used. Depending upon how it is implemented, this guidance may create duplicative requirements in certain areas, further slow the permitting process in certain areas, increase the costs of operations and result in expanded regulation of hydraulic fracturing activities by the EPA, and may therefore adversely affect even companies, such as us, that do not use diesel fuel in hydraulic fracturing activities.

In May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act pursuant to which it will collect extensive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors.

The U.S. Department of the Interior, through the Bureau of Land Management (the "BLM"), finalized a rule in 2015 requiring the disclosure of chemicals used, mandating well integrity measures and imposing other requirements relating to hydraulic fracturing on federal lands. The BLM rescinded the rule in December 2017. The BLM's rescission of the rule was challenged in the United States District Court for the Northern District of California and in March 2020 the court issued a ruling upholding BLM's rescission of the rule. That court ruling is currently being appealed.

In June 2016, the EPA finalized pretreatment standards for indirect discharges of wastewater from the oil and gas extraction industry. The regulation prohibits sending wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works.

Private Lawsuits

Lawsuits have been filed against other operators in several states, including Colorado, alleging contamination of drinking water as a result of hydraulic fracturing activities.

Greenhouse Gases

The EPA has published findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because such emissions are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings provide the basis for the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In June 2010, the EPA began regulating GHG emissions from stationary sources.

In the past, Congress has considered proposed legislation to reduce emissions of GHGs. To date, Congress has not adopted any such significant legislation, but could do so in the future. In addition, many states and regions have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Since 2014, Colorado has engaged in multiple rulemakings to adopt significant additional adopted rules regulating methane emissions from the oil and gas sector, and Colorado is expected to continue these efforts over the next several years.

The Obama administration reached an agreement during the December 2015 United Nations climate change conference in Paris pursuant to which the U.S. initially pledged to make a 26 percent to 28 percent reduction in its GHG emissions by 2025 against a 2005 baseline and committed to periodically update this pledge every five years starting in 2020 (the "Paris Agreement"). In June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement. In November 2019, the U.S. formally notified the United Nations of its intention to withdraw from the Paris Agreement. The notification began a one-year process for withdrawal on November 4, 2020. On January 20, 2021, President Joe Biden executed an executive order to re-enter the Paris Agreement.

Regulation of methane and other GHG emissions associated with oil and natural gas production could impose significant requirements and costs on our operations.

Air Quality

Our operations are subject to the CAA and comparable state and local requirements. The CAA contains provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and state governments continue to develop regulations to implement these requirements. We may be required to make certain capital investments 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. See the footnote titled *Commitments and Contingencies - Litigation and Legal Items* to our consolidated financial statements included elsewhere in this report for further information regarding the Clean Air Act Section 114 Information Request that we received from the EPA.

In June 2016, the EPA implemented new requirements focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The rules imposed, among other things, new requirements for leak detection and repair, control requirements for oil well completions, replacement of certain pneumatic pumps and controllers and additional control requirements for gathering, boosting and compressor stations. In September 2018, the EPA proposed revisions to the 2016 rules. The proposed amendments address certain technical issues raised in administrative petitions and include proposed changes to, among other things, the frequency of monitoring for fugitive emissions at well sites and compressor stations. In September 2020, the EPA issued a new rule which amended the 2016 requirements. In this rule, the EPA removed all sources in the transmission and storage segment of the oil and natural gas industry from regulation. The rule also rescinded the methane requirements in the 2016 regulations and loosened monitoring and repair regulations aimed at preventing methane leaks. The new rule was challenged in the U.S. Court of Appeals for the D.C. Circuit, but in October 2020 the Court declined to issue a permanent stay of the new rule while it considered the merits of the challenge. The new rule therefore is currently in effect. However, the future of the new rule is in flux as the Court could vacate the rule such that the original 2016 regulations would go back into effect.

In November 2016, the BLM finalized rules to further regulate venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian leases (the “2016 Rule”). The 2016 Rule required additional controls and impose new emissions and other standards on certain operations on applicable leases, including committed state or private tracts in a federally approved unit or communitized agreement that drains federal minerals. In September 2018, the BLM published a final rule that revised the 2016 Rule (the “2018 Revised Rule”). The 2018 Revised Rule, among other things, rescinded the 2016 Rule requirements related to waste-minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels and leak detection and repair. The 2018 Revised Rule also revised provisions related to venting and flaring. Environmental groups and the States of California and New Mexico filed challenges to the 2018 rule in the United States District Court for the Northern District of California, and in July 2020, the United States District Court for the Northern District of California vacated BLM’s 2018 Revised Rule. However, in October 2020, the United States District Court for the District of Wyoming issued a ruling vacating the 2016 Rule, holding that BLM exceeded its statutory authorities and acted arbitrarily. That ruling is expected to be appealed.

In 2019, the EPA increased the state of Colorado’s non-attainment ozone classification for the Denver Metro North Front Range Ozone Eight-Hour Non-Attainment ("Denver Metro/North Front Range NAA") area from "moderate" to “serious” under the 2008 national ambient air quality standard ("NAAQS"). This increase in non-attainment status to "serious" triggered significant additional obligations for the state under the CAA and resulted in Colorado adopting new and more stringent air quality control requirements in December 2020 that are applicable to our operations. Based on current air quality monitoring data, it is expected that the Denver Metro/North Front Range NAA will be further "bumped-up" to "severe" status in 2021 or 2022. This will trigger additional obligations for the state under the CAA and will result in new and more stringent air quality permitting and control requirements, which may in turn result in significant costs and delays in obtaining necessary permits applicable to our operations.

SB 19-181 also requires, among other things, that the Air Quality Control Commission ("AQCC") adopt additional rules to minimize emissions of methane and other hydrocarbons and nitrogen oxides from the entire oil and gas fuel cycle. The AQCC has undertaken a multi-year rulemaking process to implement the requirements of SB 19-181, including a rulemaking to require continuous emission monitoring equipment at oil and gas facilities. Between December 2019 and December 2020, the AQCC completed several rulemakings as a result of SB 19-181, adopting significant additional and new emission control requirements applicable to oil and gas operations, including, for example, hydrocarbon liquids unloading control requirements, increased LDAR frequencies for facilities in certain proximity to occupied areas, and emission control requirements for certain large natural gas fired engines. The AQCC plans to conduct additional rulemakings related to SB 19-181 in 2021.

Additionally, in response to HB 19-1261, which established statewide greenhouse gas reduction targets, Colorado, on September 30, 2020, released a public comment draft of its Greenhouse Gas Pollution Reduction Roadmap, which details early action steps the state can take toward meeting the near-term goals of reducing greenhouse gas (GHG) pollution 26% by 2025 and 50% by 2030 from 2005 levels. On October 23, 2020, the AQCC issued the Resolution to Ensure Greenhouse Gas Reduction Goals Are Met in support of the roadmap, which estimates emission reductions needed from the oil and gas sector of 36% by 2025 and 50% by 2030. To meet these targets, the CDPHE has also initiated a stakeholder process to develop and consider additional greenhouse gas reduction strategies from the oil and gas sector, to be finalized in a 2021 AQCC rulemaking.

State-level rules applicable to our operations include regulations imposed by the Colorado Department of Public Health and Environment's ("CDPHE") Air Quality Control Commission, including stringent requirements relating to monitoring, recordkeeping and reporting matters. In 2020, the COGCC relied in part on a previously-performed human health risk assessment in adopting new siting requirements. The COGCC also generally prohibited the venting or flaring of natural gas during drilling, completion, and production operations.

While the State of Texas has not formally conducted a recent rulemaking related to air emissions, scrutiny of oil and gas operations and the rules affecting them have increased in recent years. For example, EPA and environmental non-governmental organizations have conducted flyovers with optical gas imaging cameras to survey emissions from oil and gas production facilities and transmission infrastructure. In addition, the Texas Railroad Commission has increased oversight related to flaring, with reporting reviews and site inspections. While none of these activities increases our compliance obligations, they signal the potential for increased enforcement and possible rulemaking in the future.

Water Quality

The federal Clean Water Act ("CWA") and analogous state laws impose strict controls concerning the discharge into regulated waterbodies and wetlands of pollutants and fill material, including spills and leaks of crude oil and other substances. The CWA also requires approval and/or permits prior to construction, where construction will disturb certain wetlands or other federally regulated waters of the U.S. ("WOTUS"). In October 2019, the EPA and the Army Corps of Engineers ("USACE") issued a final rule to repeal previous regulations (the "2019 Repeal Rule") and implement the 1986 WOTUS regulations and guidance nationwide, until a new replacement rule could be adopted. The 2019 Repeal Rule became effective on December 23, 2019. However, numerous legal challenges to the 2019 Repeal Rule have been filed in federal court.

On April 21, 2020, the EPA and USACE issued a final new replacement on the scope of regulated WOTUS, titled the Navigable Waters Protection Rule ("2020 Rule"). The 2020 Rule was judicially challenged in several different lawsuits, which are still pending, but it was preliminarily enjoined only in Colorado and went into effect in all other states on June 22, 2020. In Colorado only, the former 1986 WOTUS rule and related guidance will control until the lawsuit there is resolved. In all other states, the 2020 Rule will remain in effect unless it is invalidated in one or more of the pending lawsuits, or unless it is replaced by the incoming Biden administration, which would take many months. The 2020 Rule generally regulates four categories of “jurisdictional waters": (i) territorial seas and traditional navigable waters (i.e., large rivers); (ii) perennial and intermittent tributaries of these waters; (iii) certain lakes, ponds and impoundments; and (iv) wetlands adjacent to jurisdictional waters. The 2020 Rule also includes 12 categories of exclusions, or “non-jurisdictional” waters, including groundwater, ephemeral features and diffuse stormwater run-off over upland areas. In particular, the 2020 Rule regulates fewer wetlands areas than were regulated under the 1986 rule and the 2015 Clean Water Rule, because it does not regulate wetlands that are not adjacent to jurisdictional waters. If the 2020 WOTUS Rule is invalidated in one or more pending lawsuits, or if it is replaced by a new, more stringent rule on the scope of WOTUS by the incoming administration, it would likely change the scope of the CWA’s jurisdiction, which could result in increased costs and delays with respect to obtaining permits for discharges of pollutants or dredge and fill activities in waters of the U.S., including regulated wetland areas.

In January 2017, the USACE issued revised and renewed streamlined general nationwide permits that are available to satisfy permitting requirements for certain work in streams, wetlands and other regulated waters of the U.S. under Section 404 of the CWA and the Rivers and Harbors Act. The new nationwide permits took effect in March 2017, or when certified by each state, whichever was later. The oil and gas industry broadly utilizes Nationwide Permits 12, 14 and 39 for the construction, maintenance and repair of pipelines, roads and drill pads, respectively, and related structures in waters of the U.S. that impact less than a half-acre of waters of the U.S. and meet the other criteria of each nationwide permit.

In May 2020, a federal court in Montana enjoined the use of Nationwide Permit 12 to construct new oil and gas-related pipelines, on the basis that the USACE had not properly consulted with the U.S. Fish and Wildlife Service when that permit was renewed in 2017. The U.S. Supreme Court in July 2020 significantly narrowed the Montana court's injunction to cover only the challenged XL Pipeline. The Montana court's substantive decision is now on appeal to the Ninth Circuit, whose ultimate ruling could affect the oil and gas industry's ability to use this streamlined permit. In the meantime, in September 2020, the USACE issued a proposal to revise and reissue all 52 current nationwide permits, including No. 12, to lessen the burden on the energy industry and address the flaws alleged in the Montana lawsuit. Among other things, under that proposal existing Nationwide Permit 12 would be broken up into three new separate nationwide permits, with the proposed new Nationwide Permit 12 being limited solely to construction and maintenance of oil and gas pipelines, with other utility-related structures covered by the two new nationwide permits. The proposed new No. 12 would also have decreased requirements for pre-construction notification to the USACE. It is unknown at this time whether that proposed rule will be finalized by the end of the current administration or, if not, whether it will be abandoned or revised by the incoming administration. If the current or revised version of Nationwide Permit 12 is invalidated or stayed by the courts, it would increase the costs and delays for oil and gas operators to construct or maintain pipelines that cross jurisdictional waters of the U.S.

The CWA also regulates storm water run-off from crude oil and natural gas facilities and requires storm water discharge permits for certain activities. Spill Prevention, Control and Countermeasure ("SPCC") requirements of the CWA require appropriate secondary containment, load out controls, piping controls, berms and other measures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture or leak.

Endangered Species

The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act and bald and golden eagles under the Bald and Golden Eagle Protection Act. Some of our operations may be located in areas that are or may be designated as habitats for endangered or threatened species or that may attract migratory birds, bald eagles or golden eagles.

Other

In October 2015, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration proposed to expand its regulations in a number of ways, including increased regulation of gathering lines, even in rural areas, and proposed additional standards to revise safety regulations applicable to onshore gas transmission and gathering pipelines in 2016.

Crude oil production is subject to many of the same operating hazards and environmental concerns as natural gas production, but is also subject to the risk of crude oil spills. In addition to SPCC requirements, the Oil Pollution Act of 1990 ("OPA") subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from crude oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Historically, we have not experienced any significant crude oil discharge or crude oil spill problems.

In May 2015, the U.S. Department of Transportation issued a final rule regarding the safe transportation of flammable liquids by rail. The final rule imposes certain requirements on "offerors" of crude oil, including sampling, testing and certification requirements.

In February 2018, the COGCC comprehensively amended its regulations for oil, gas and water flowlines to expand requirements addressing flowline registration and safety, integrity management, leak detection and other matters. In November 2019, the COGCC further amended its flowline regulations pursuant to SB 19-181 to impose additional requirements regarding flowline mapping, operational status, certification and abandonment, among other things.

We are also subject to rules regarding worker safety and similar matters promulgated by the U.S. Occupational Safety and Health Administration ("OSHA") and other governmental authorities. OSHA has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. To this end, OSHA adopted a new rule governing employee exposure to silica, including during hydraulic fracturing activities, in March 2016.

Human Capital Resources

Employee Headcount

As of December 31, 2020, we had 520 full-time employees, 235 of whom are employed in field operations.

Employee Engagement

Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. Therefore, we recognize and support the growth of our employees by offering internal and external development programs. We utilize an online training platform to allocate and track employee trainings, as well as offering on-demand developmental training content. Lastly, to remind our employees of PDC's values, we require all employees to attend an annual harassment awareness training.

We conduct an annual employee satisfaction survey where employees from each of our offices are provided an opportunity for their opinions to be voiced on how we can improve as a company. We report results back to our board of directors, management team and employees and take actions to address areas of employee concern. On a company-wide level, we encourage a culture of volunteerism and have an annual day of service which garners participation from the vast majority of our employees. Additionally, we believe diversity and inclusion provides a business with innovation and a successful workforce. We formed an employee-led diversity and inclusion project team in 2020 that will identify areas for growth and improvement that will build on our current efforts in respect of diversity and inclusion.

Safety Culture

We are committed to the health, safety, and welfare of our employees, contractors, and neighbors. We regularly update our safety policies and procedures to ensure we are meeting or exceeding new requirements and adopting new technologies that improve our responsible operations. Additionally, all PDC field employees receive safety training upon hire, along with frequent meetings and refreshers to reinforce safety as a core value and our most important strategic priority.

PDC utilizes a field monitoring room, which is tied into our field automation, that is staffed 24 hours a day and 365 days a year to identify emergency situations and allows for quick field response. The automation capabilities on a facility can vary from measuring tank levels to security cameras to remote emergency shut-down capabilities. The field monitoring room, in combination with our daily inspections performed on producing locations, facilitates proactive response to events that need attention.

Our continual commitment to safety has resulted in improving safety records, even as operations have grown. At least since the time Occupational Safety and Health Administration ("OSHA") began requiring record-keeping and publication of health and safety information in 1972, we have not had any employee work-related fatalities. A commonly used measure of an organization's safety performance is Total Recordable Incident Rate ("TRIR"), which equates to the number of injuries requiring medical treatment per 100 full-time employees during a one-year period. We monitor this performance measure and communicate it broadly across the company. We also include both TRIR and Preventable Vehicle Accident Rate ("PVAR") as part of our quantitative performance metrics within our annual incentive program, to prioritize the importance of safety within our company. Our TRIR and PVAR remained notably low for 2020 and 2019.

Employee Compensation and Benefits

Our compensation program is designed to provide the proper incentives to attract, retain and reward employees to achieve results related to our core values and strategic priorities. The structure of our compensation program provides incentives for both short-term and long-term performance. We also seek fairness in total compensation and benefits with reference to external benchmarking against our peers within the industry. All full-time employees are eligible for health insurance, paid and unpaid leaves, a retirement plan and life and disability/accident coverage.

Our employees are not covered by collective bargaining agreements. We consider relations with our employees to be positive.

WHERE YOU CAN FIND ADDITIONAL INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC, which are maintained and available at *www.sec.gov*. Our SEC filings are also available free of charge from our website at *www.pdce.com* as soon as reasonably practicable after such material is filed with, or furnished to, the SEC. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact PDC Energy, Inc., Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call (303) 860-5800.

We recommend that you view our website for additional information, as we routinely post information that we believe is important for investors. Our website can be used to access such information as our recent news releases, committee charters, code of business conduct and ethics, stockholder communication policy, director nomination procedures, sustainability report and our whistle blower hotline. While we recommend that you view our website, the information available on our website is not part of this report and is not incorporated by reference.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as the value of an investment in our common stock or other securities.

Risks Relating to the Global COVID-19 Pandemic

Our operations have been adversely affected as a result of the ongoing global COVID-19 pandemic and its impacts on crude oil demand and pricing. We expect those impacts to continue in the near-term and we may experience additional impacts in the future. For example:

- Prolonged depressed crude oil prices may have adverse effects on the financial wellbeing of our business, including with respect to revenue, profitability, cash flows and liquidity; quantity and present value of our reserves; the borrowing base under our revolving credit facility; and access to other sources of capital;
- Negative financial impacts may lead to distress and restructuring events affecting working interest partners, vendors, contractors, service providers and other counterparties;
- Negative financial impacts to our business partners may cause delays or failure to pay service providers, which could result in liens being filed against our real and personal property;
- Reduced capital spending and declines in revenues have led to temporary and permanent reductions in our work force and decreases to our director, executive and employee compensation, which may affect our ability to attract and retain experienced technical and other professional personnel;
- Our reduced drilling program may result in losses of acreage due to lease expirations, which could result in impairment charges and the loss of future drilling opportunities;
- State and local orders, ordinances and guidance related to COVID-19 have forced a significant portion of our employees to work remotely, which may result in decreased productivity and continuity among the employee base;
- Current market conditions and impacts on our business generally may lead to an increased risk of litigation; and
- The cumulative effects of COVID-19 on the economy may result in a long-term global recession or depression.

Risks Relating to Our Business and the Industry

Crude oil, natural gas and NGL prices fluctuate and declines in these prices, or an extended period of low prices, can significantly affect the value of our assets and our financial results and may impede our growth.

Our revenue, profitability, cash flows and liquidity depend in large part upon the prices we receive for our crude oil, natural gas and NGLs. Changes in prices affect many aspects of our business, including:

- our revenue, profitability and cash flows;
- our liquidity;
- the quantity and present value of our reserves;
- the borrowing base under our revolving credit facility and access to other sources of capital; and
- the nature and scale of our operations.

The markets for crude oil, natural gas and NGLs are often volatile, and prices may fluctuate in response to, among other things:

- relatively minor changes in regional, national or global supply and demand;
- regional, national or global economic conditions, and perceived trends in those conditions;
- geopolitical factors, such as events that may reduce or increase production from particular oil-producing regions and/or from members of the Organization of Petroleum Exporting Countries ("OPEC"), and global events, such as the ongoing COVID-19 pandemic; and
- regulatory changes.

The price of oil has historically been volatile, due in recent years to a combination of factors including increased U.S. supply and global economic concerns. As a result of the ongoing impact of the COVID-19 pandemic and actions of members of OPEC, in 2020, oil prices ranged from highs of approximately $59 per barrel to lows of approximately negative $40 per barrel (due to depressed demand and insufficient storage capacity, particularly at the WTI physical settlement location in Cushing, Oklahoma). Prices for natural gas and NGLs have also experienced substantial volatility. If we reduce our capital expenditures due to low prices, natural declines in production from our wells will likely result in reduced production and therefore reduced cash flow from operations, which would in turn further limit our ability to make the capital expenditures necessary to replace our reserves and production.

In addition to factors affecting the price of crude oil, natural gas and NGLs generally, the prices we receive for our production are affected by factors specific to us and to the local markets where the production occurs. The prices that we receive for our production are generally lower than the relevant benchmark prices that are used for calculating commodity derivative positions. These differences, or differentials, are difficult to predict and may widen or narrow in the future based on market forces. Differentials can be influenced by, among other things, local or regional supply and demand factors and the terms of our sales contracts. Over the longer term, differentials will be significantly affected by factors such as investment decisions made by providers of midstream facilities and services, refineries and other industry participants and the overall regulatory and economic climate. For example, increases in U.S. domestic oil production generally, or in production from particular basins, may result in widening differentials. We may be materially and adversely impacted by widening differentials on our production and decreasing commodity prices.

We are subject to complex federal, state, local and other laws and regulations that adversely affect the cost and manner of doing business. Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning crude oil and natural gas wells and associated facilities. Under these laws and regulations, we could also be liable for personal injuries, property damage and natural resource or other damages, and could be required to change, suspend or terminate operations. A summary of certain laws and regulations that apply to us and some potential changes to those laws and regulations is set forth in *Items 1 and 2 - Business and Properties - Governmental Regulation*. Any of the currently applicable laws and regulations could be amended, including in ways that we do not anticipate, and those changes could adversely affect our operations.

From time to time, we have been subject to sanctions and lawsuits relating to alleged noncompliance with regulatory requirements. For example, in October 2017, in order to settle a lawsuit brought against us by the U.S. Department of Justice, on behalf of the EPA and the State of Colorado, we entered into a consent decree pursuant to which we paid a fine and agreed to implement certain operational changes. The lawsuit claimed that we failed to operate and maintain certain equipment in compliance with applicable law. In addition, as a result of the SRC Acquisition, we are subject to the obligations and requirements of a 2018 Compliance Order on Consent ("COC") entered into by SRC with CDPHE, applicable to certain SRC oil and gas production facilities we acquired from SRC. The COC resolved SRC's alleged violations related to storage tank emissions and contains requirements similar to those contained in our consent decree.

The regulatory environment in which we operate also changes frequently, often through the imposition of new or more stringent environmental and other requirements, some of which may apply retroactively. We cannot predict the nature, timing, cost or effect of such additional requirements, but they may have a variety of adverse effects on us. The types of regulatory changes that could impact our operations vary widely and include, but are not limited to, the following:

- As discussed in *Items 1 and 2, Business and Properties - Governmental Regulation*, the COGCC completed extensive rulemaking hearings under SB 19-181 in 2020, which resulted in the adoption of new requirements for setbacks, permitting, siting cumulative and surface impacts, asset transfers, venting and flaring, and remediation. The implementation of the final rules, particularly as they relate to mandatory setbacks between wells and building units, could have a significant adverse effect on our unpermitted locations and therefore on our future inventory and reserves. Other final rules could have a significant adverse effect on our future operations as well. The COGCC is still in the process of issuing guidance and direction regarding the new requirements, and we cannot predict the impact of these requirements on our inventory and operations.
- Substantially all of our drilling activities involve the use of hydraulic fracturing, and proposals are made from time to time at the federal, state and local levels to further regulate, or to ban, hydraulic fracturing practices. Additional laws or regulations regarding hydraulic fracturing could, among other things, increase our costs, reduce our inventory of economically viable drilling locations and reduce our reserves.

- Federal and various state, local and regional governmental authorities have implemented, or considered implementing, regulations that seek to limit or discourage the emission of carbon, methane and other GHGs. For example, the EPA has made findings and issued regulations that require us to establish and report an inventory of greenhouse gas emissions, and the state of Colorado has adopted rules regulating methane emissions from oil and gas operations. Additional laws or regulations intended to restrict the emission of GHGs could require us to incur additional operating costs and could adversely affect demand for the oil, natural gas and NGLs that we sell. These new laws or rules could, among other things, require us to install new emission controls on our equipment and facilities, acquire allowances to authorize our GHG emissions, pay taxes related to our emissions and administer and manage a GHG emissions program. In addition, like other energy companies, we could be named as a defendant in GHG-related lawsuits.
- Proposals are made from time to time to amend U.S. federal and state tax laws in ways that would be adverse to us, including by eliminating certain key U.S. federal income tax preferences currently available with respect to crude oil and natural gas exploration and production. The changes could include (i) the repeal of the percentage depletion deduction for crude oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Also, state severance taxes may increase in the states in which we operate. This could adversely affect our existing operations in the relevant state and the economic viability of future drilling.
- The development of new environmental initiatives or regulations related to the acquisition, withdrawal, storage and use of surface water or groundwater or treatment and discharge of water waste, may limit our ability to use techniques such as hydraulic fracturing, increase our development and operating costs and cause delays, interruptions or termination of our operations, any of which could have an adverse effect on our operations and financial condition.

A substantial part of our crude oil, natural gas and NGLs production is located in the Wattenberg Field, making us vulnerable to risks associated with operating primarily in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing formations.

Although we have significant leasehold positions in the Delaware Basin in Texas, our current production is primarily located in the Wattenberg Field in Colorado. Because our production is not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including natural disasters, government regulations and midstream interruptions.

For example, bottlenecks in processing and transportation that have occurred in some recent periods in the Wattenberg Field have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Similarly, the concentration of our producing assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules that could adversely affect development activities or production relating to those formations. Such an event could have a material adverse effect on our results of operations and financial condition. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field and the Delaware Basin, the demand for, and cost of, drilling rigs, equipment, supplies, chemicals, personnel and oilfield services often increase as well. Any shortages or increased costs could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital forecast, which could have a material adverse effect on our business, financial condition or results of operations. All of the producing properties and reserves we acquired in the SRC Acquisition are located in the Wattenberg Field. As a result, the transaction increased the risks we face with respect to the geographic concentration of our properties.

The marketability of our production is dependent upon transportation and processing facilities, the capacity and operation of which we do not control. Market conditions or operational impediments affecting midstream facilities and services could hinder our access to crude oil, natural gas and NGL markets, increase our costs or delay production. Our efforts to address midstream issues may not be successful.

Our ability to market our production depends in substantial part on the availability, proximity and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production may be curtailed and our results of operations will be adversely affected. In addition to causing production curtailments, capacity constraints can also reduce the price we receive for the crude oil, natural gas and NGLs we produce.

We rely on third parties to continue to construct additional midstream facilities and related infrastructure to accommodate our growth, and the ability and willingness of those parties to do so is subject to a variety of risks. For example:

- Decreases in commodity prices in recent years have resulted in reduced investment in midstream facilities by some third parties;
- Various interest groups have protested the construction of new pipelines, and particularly pipelines near water bodies, in various places throughout the country, and protests have at times physically interrupted pipeline construction activities;
- Some upstream energy companies have sought to reject volume commitment agreements with midstream providers in bankruptcy proceedings, and the risk that such efforts will succeed, or that upstream energy company counterparties will otherwise be unable or unwilling to satisfy their volume commitments, may have the effect of reducing investment in midstream infrastructure; and
- The possibility that new or amended regulations, including regulations that increase mandatory setbacks or enhance local control of oil and gas development, could result in severely curtailed drilling activities in Colorado and may discourage investment in midstream facilities.

Like other producers, we from time to time enter into volume commitments with midstream providers in order to induce them to provide increased capacity. If our production falls below the level required under these agreements, we could be subject to substantial penalties.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in substantial lease renewal costs or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering our undeveloped acreage, our leases for such acreage will expire. The cost to renew such leases may increase significantly and we may not be able to renew such leases on commercially reasonable terms or at all. Unexpected lease expirations could occur if our actual drilling activities differ materially from our current expectations, and this could result in impairment charges. The risk of lease expiration is greater at times and in areas where the pace of our exploration and development activity slows. Our ability to drill and develop the locations necessary to maintain our leases depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

We may incur losses as a result of title defects in the properties in which we invest or acquire.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform record title examinations before we acquire oil and gas leases and related interests. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of or recycle the water we use at a reasonable cost, in a timely manner and within applicable environmental rules.

Drilling and development activities such as hydraulic fracturing require the use of water and result in the production of wastewater. Our operations could be adversely impacted if we are unable to locate sufficient amounts of water or dispose of or recycle water used in our exploration and production operations. The quantity of water required in certain completion operations, such as hydraulic fracturing, and changing regulations governing usage may lead to water constraints, supply concerns and regulatory issues, particularly in relatively arid climates such as eastern Colorado and western Texas. For example, increased drilling activity in the Delaware Basin in recent years has led to heightened concerns about water supply issues in the area and this may lead to regulatory actions, including rules providing local governments greater authority over water use, that adversely impact our operations.

Our operations depend on being able to reuse or dispose of wastewater in a timely and economic fashion. Wastewater from oil and gas operations is often disposed of through underground injection. Wells in the Delaware Basin typically produce relatively large amounts of water that require disposal and an increased number of earthquakes have been detected in the Delaware Basin in recent years. Some studies have linked earthquakes, or induced seismicity, in certain areas to underground injection, which is leading to increased public and regulatory scrutiny of injection safety. For example, in November 2020, the COGCC adopted various new requirements on the underground injection of fluid waste.

Reduced commodity prices could result in significant impairment charges and significant downward revisions of proved reserves.

Commodity prices are volatile. Significant and rapid declines in prices have occurred in the past and may occur in the future. Low commodity prices could result in, among other things, significant impairment charges in the future. For example, we incurred impairment charges in a number of recent periods, including charges of $882.4 million and $38.5 million in 2020 and 2019, respectively, to write down assets. Similarly, the significant decline in commodity pricing during 2020 resulted in a reduced year-end proved reserve NYMEX price of $39.57 per barrel of crude and $1.99 per MMBtu of natural gas, a decrease of 29% and 23% respectively from 2019. The decline in pricing resulted in a downward revision of 28.2 MMBoe to reserves for year-end 2020 when compared to year-end 2019. The cash flow model we use to assess properties for impairment includes numerous assumptions, such as management’s estimates of future oil and gas production and commodity prices, the outlook for forward commodity prices and operating and development costs. All inputs to the cash flow model must be evaluated at each date the estimate of future cash flows is made for each producing basin. A significant decrease in long-term forward prices could result in a significant impairment for our properties.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. In determining the estimates of reserve and economic evaluations, management utilizes independent petroleum engineers. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate. The reserve estimates are based on assumptions regarding commodity prices, production levels and operating and development costs that may prove to be incorrect. Any significant variance from these assumptions to actual results could greatly affect:

- the economically recoverable quantities of crude oil, natural gas and NGLs attributable to any particular group of properties;
- future depreciation, depletion and amortization (“DD&A”) rates and amounts;
- impairments in the value of our assets;
- the classifications of reserves based on risk of recovery;
- estimates of future net cash flows;
- timing of our capital expenditures; and
- the amount of funds available for us to borrow under our revolving credit facility.

Some of our reserve estimates must be made with limited production histories, which renders these estimates less reliable than those based on longer production histories. Further, reserve estimates are based on the volumes of crude oil, natural gas and NGLs that are anticipated to be economically recoverable from a given date forward based on economic conditions that exist at that date. The actual quantities of crude oil, natural gas and NGLs recovered will be different than the reserve estimates, in part because they will not be produced under the same economic conditions as are used for the reserve calculations. In addition, quantities of probable and possible reserves by definition are inherently more risky than proved reserves, in part because they have greater uncertainty associated with the recoverable quantities of hydrocarbons.

At December 31, 2020, approximately 56 percent of our estimated proved reserves were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our PUDs into proved developed reserves, including approximately $2.3 billion during the five years ending December 31, 2025, as estimated in the calculation of our standardized measure of oil and gas activity. The estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC's reserve reporting rules, PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of initial booking, and we may therefore be required to downgrade any PUDs that are not developed within this five-year time frame.

The present value of the estimated future net cash flows from our proved reserves is not necessarily the same as the current market value of those reserves. Pursuant to SEC rules, the estimated discounted future net cash flows from our proved reserves, and the estimated quantity of those reserves, are based on the prior year's first day of the month 12-month average crude oil and natural gas index prices. However, factors such as actual prices we receive for crude oil and natural gas and hedging instruments, the amount and timing of actual production, the amount and timing of future development costs, the supply of and demand for crude oil, natural gas and NGLs and changes in governmental regulations or taxation, also affect our actual future net cash flows from our properties. The timing of both our production and incurrence of expenses in connection with the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating discounted future net cash flows (the rate required by the SEC) may not be the most appropriate discount factor based on interest rates currently in effect and risks associated with our properties or the industry in general.

Unless reserves are replaced as they are produced, our reserves and production will decline, which would adversely affect our future business, financial condition and results of operations. We may not be able to develop our identified drilling locations as planned.

Producing crude oil, natural gas and NGL reservoirs are generally characterized by declining production rates that may vary over time and exceed our estimates depending upon reservoir characteristics and other factors. Our future reserves and production and, therefore, our cash flows and income, are highly dependent on our ability to efficiently develop and exploit our current reserves and to economically find or acquire additional recoverable reserves. We may not be able to develop, discover or acquire additional reserves to replace our current and future production at acceptable costs. Our failure to do so would adversely affect our future operations, financial condition and results of operations.

We have identified a number of well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including:

- crude oil, natural gas and NGL prices;
- the availability and cost of capital;
- drilling and production costs;
- availability and cost of drilling rigs, and equipment, supplies, chemicals, personnel and oilfield services;
- drilling results;
- lease expirations or limitations as to depth;
- midstream constraints;
- access to and availability of water sourcing and distribution systems;
- regulatory approvals; and
- other factors.

Because of these factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce crude oil, natural gas or NGLs from these or any other potential well locations. In addition, the number of drilling locations available to us will depend in part on the spacing of wells in our operating areas. An increase in well density in an area could result in additional locations in that area, but a reduced production performance from the area on a per-well basis. Further, certain of the horizontal wells we intend to drill in the future may require pooling of our lease interests with the interests of third parties. Some states, including Colorado, allow the involuntary pooling of tracts in a relatively broad number of circumstances in order to facilitate exploration, though Colorado now requires applicants to own or secure consent from the owners of more than 45 percent of the minerals to be pooled. Other states, notably Texas, restrict involuntary pooling to a much narrower set of circumstances and consequently these states rely primarily on voluntary pooling of lands and leases. In states such as Texas where pooling is accomplished primarily on a voluntary basis, or in states such as Colorado if we cannot meet the minimum requirement for ownership and consent, it may be more difficult to form units and, therefore, more difficult to fully develop a project if we own less than all (or cannot secure the ownership or consent of the required minimum amount) of the leasehold in the proposed units or one or more of our leases in the proposed units does not provide the necessary pooling authority. If third parties in the proposed units are unwilling to pool their interests with ours, we may be unable to require such pooling on a timely basis or at all, which would limit the total horizontal wells we can drill. Further, the number of available locations will depend in part on the expected lateral lengths of the horizontal wells we drill. Because the intended lateral length of a horizontal well is subject to change for a variety of reasons, our estimated drilling locations will change over time. For this and numerous other reasons, our actual drilling activities may materially differ from those presently identified.

Our inventory of drilling projects includes locations in addition to those that we currently classify as proved, probable and possible. The development of and results from these additional projects are more uncertain than those relating to probable and possible locations, and significantly more uncertain than those relating to proved locations. We have generally accelerated the pace of our development activities in the Wattenberg Field over the past several years, and this has reduced our related inventory of drilling locations. We anticipate that our remaining locations in the field will not, on average, be as productive or as economic as many of those we have drilled in recent years, due to lower anticipated overall production or higher gas-to-oil ratios. In the Delaware Basin, our inventory is subject to, among other things, potential lease expirations and our continued analysis of geologic challenges in certain areas.

The wells we drill may not yield crude oil, natural gas or NGLs in commercially viable quantities and productive wells may be less successful than we expect.

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of hydrocarbon-bearing rocks. However, given the limitations of available data and technology, our geologists cannot know conclusively prior to drilling and testing whether crude oil, natural gas or NGLs will be present in sufficient quantities to repay drilling or completion costs and generate a profit. Furthermore, even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques do not enable our geologists to be certain as to the quantity of the hydrocarbons in those structures. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. If a well is determined to be dry or uneconomic, which can occur even though it contains some crude oil, natural gas or NGLs, it is classified as a dry hole and must be plugged and abandoned in accordance with applicable regulations. This generally results in the loss of the entire cost of drilling and completion to that point, the cost of plugging and lease costs associated with the prospect. Even wells that are completed and placed into production may not produce sufficient crude oil, natural gas and NGLs to be profitable, or they may be less productive and/or profitable than we expected. For example, the data we use to model anticipated results from wells in a particular area may prove to be not representative of actual results from typical wells in the area, and this could result in production that falls short of estimates reflected in our internal business plans and/or guidance, "type curve" or other disclosures we make to the public. This risk is higher for us in certain areas in the Delaware Basin that have relatively complex geological characteristics and correspondingly greater variability in well results. In addition, initial results from a well are not necessarily indicative of its performance over a longer period.

Drilling for and producing crude oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling can be unprofitable, not only due to dry holes, but also due to curtailments, delays or cancellations as a result of other factors, including:

- pressures or irregularities in geological formations;
- fires;
- floods, winter storms and other natural disasters and adverse weather conditions;
- loss of well control;
- loss of drilling fluid circulation and other facility or equipment malfunctions;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delays in the delivery of equipment and services;
- unanticipated environmental liabilities; and
- compliance with environmental and other governmental requirements.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and regulatory penalties. For example, a loss of containment of hydrocarbons during drilling activities could potentially subject us to civil and/or criminal liability and the possibility of substantial costs, including for environmental remediation. We maintain insurance against various losses and liabilities arising from our operations; however, insurance against certain operational risks may not be available or may be prohibitively expensive relative to the perceived risks presented. For example, we may not have coverage with respect to a pollution event if we are unaware of the event while it is occurring and are therefore unable to report the occurrence of the event to our insurance company within the time frame required under our insurance policy. Thus, losses could occur for uninsurable or uninsured risks or for amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance and/or governmental or third-party responses to an event could have a material adverse effect on our business activities, financial condition and results of operations. We are currently involved in various remedial and investigatory activities at some of our wells and related sites.

In addition, certain technical risks relating to the drilling of horizontal wells - including those relating to our ability to fracture stimulate the planned number of stages and to successfully run casing the length of the well bore - have increased in recent years because we have increased the average lateral length of the horizontal wells we drill. Longer-lateral wells are also typically more expensive and require more time for preparation. In addition, we have transitioned to the use of multi-well pads instead of single-well sites. The use of multi-well pad drilling increases some operational risks because problems affecting the pad or a single well could adversely affect production from all of the wells on the pad. Pad drilling can also make our overall production, and therefore our revenue and cash flows, more volatile, because production from multiple wells on a pad will typically commence simultaneously. While we believe that we will be better served by using multi-well pads with longer lateral wells, the risk component involved in such drilling will be increased in some respects, with the result that we might find it more difficult to achieve economic success in our drilling program.

The inability of one or more of our customers or other counterparties to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from our crude oil, natural gas and NGLs sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our commodity derivatives expose us to credit risk in the event of nonperformance by counterparties. Nonperformance by our customers or derivative counterparties may adversely affect our financial condition and profitability. We face similar risks with respect to our other counterparties, including the lenders under our revolving credit facility and the providers of our insurance coverage.

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

We frequently own less than all of the working interest in the oil and gas leases on which we conduct operations. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities, arising from the actions of the other owners. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, may declare bankruptcy. In the event any of our project partners does not pay its share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover the costs from the partner. This could materially adversely affect our financial position.

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

Our industry is characterized by rapid and significant technological advancements. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those or other new technologies at substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future 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 were unable to use the most advanced technology, our business, financial condition and results of operations could be materially adversely affected.

Competition in our industry is intense, which may adversely affect our ability to succeed.

Our industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce crude oil, natural gas and NGLs, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive properties and exploratory prospects or evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, larger companies may have a greater ability to continue exploration activities during periods of low commodity prices. Larger competitors may also be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which could adversely affect our competitive position. These factors could adversely affect our operations and our profitability.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our future success depends to a large extent on the services of our key employees. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

A failure to complete successful acquisitions would limit our ability to replace our reserves and impact our financial condition.

Because our crude oil and natural gas properties are depleting assets, our future reserves, production volumes and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. In addition, we continue to strive to achieve greater efficiencies in our drilling program, and our ability to do so is dependent in part on our ability to complete asset exchanges and other acquisitions that allow us to increase our working interests in particular properties. We may not be able to identify attractive acquisition opportunities, and if we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. If we are unable to complete suitable acquisitions on acceptable terms, it will be more difficult to replace our reserves, and an inability to replace our reserves would have a material adverse effect on our financial condition and results of operations.

Acquisitions of properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.

Acquisitions of producing and undeveloped properties, including the SRC Acquisition, have been an important part of our growth over time. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future commodity prices, operating costs, title issues and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we generally perform engineering, environmental, geological and geophysical reviews of the acquired properties that we believe are generally consistent with customary industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may not always discover structural, subsurface and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, we often acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. We may not be entitled to contractual indemnification associated with acquired properties. We often acquire interests in properties on an “as is” basis with no or limited remedies for breaches of representations and warranties. Therefore, we could incur significant unknown liabilities, including environmental liabilities or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

Additionally, significant acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or may be in different geographic locations than our existing properties. These factors can increase the risks associated with an acquisition. Acquisitions also present risks associated with the additional indebtedness that may be required to finance the purchase price and any related increase in interest expense or other related charges.

The SRC Acquisition presented a number of the foregoing risks - for example, because closing has occurred, we have no recourse if we discover unanticipated liabilities or other problems with the properties we acquired in the transaction. In addition, those risks are greater than they were in the case of most of our previous acquisitions given the larger size of the SRC Acquisition.

Some of our acquisitions are structured as asset trades or exchanges. These transactions may give rise to any or all of the foregoing risks. In addition, transactions of this type create a risk that we will undervalue the properties we transfer to the counterparty in the trade or exchange or overvalue the properties we receive. Such an undervaluation or overvaluation would result in the transaction being less favorable to us than we expected.

We operate in a litigious environment. The cost of defending any suits brought against us, and any judgments or settlements resulting from such suits, could have an adverse effect on our results of operations and financial condition.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, employment litigation, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. For example, on January 18, 2021, a purported class action lawsuit was filed against us by a royalty owner alleging we have been improperly deducting certain post-production costs from the owner’s oil royalty payments. While we intend to vigorously defend this suit, the outcome of legal proceedings is inherently uncertain. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management attention and other factors. In addition, the resolution of such a proceeding could result in penalties or sanctions, settlement costs and/or judgments, consent decrees or orders requiring a change in our business practices, any of which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties, sanctions or costs may be insufficient. Judgments and estimates to determine accruals or the anticipated range of potential losses related to legal and other proceedings could change from one period to the next, and such changes could be material. Information regarding legal proceedings can be found in *Note 12 - Commitments and Contingencies - Litigation and Legal*

Items included in *Item 8. Financial Statements and Supplementary Data* to our consolidated financial statements included elsewhere in this report.

Our business could be negatively impacted by security threats, including cybersecurity threats and other disruptions.

We face various security threats, including attempts by third parties to gain unauthorized access to, or control of, competitive information or to render data or systems corrupted or unusable; threats to the safety of our employees; threats to the security of our infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. There can be no assurance that the procedures and controls we use to monitor these threats and mitigate our exposure to them will be sufficient to prevent them from materializing.

Our industry has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain exploration, development and production activities. We depend on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to store, transmit, process and record sensitive information (including but not limited to trade secrets, employee information and financial and operating data), communicate with our employees and business partners, and for many other activities related to our business. In addition, computer systems control the oil and gas production and processing equipment that are necessary to deliver our production to market. A disruption or failure of these systems, or of the networks and infrastructure on which they rely, may cause damage to critical production, distribution and/or storage assets, delay or prevent delivery to markets, or make it difficult to accurately account for production and settle transactions. The continuing and evolving threat of cybersecurity attacks has resulted in increased regulatory focus on prevention, which could potentially elevate costs, and failure to comply with these regulations could result in penalties and potential legal liability.

As dependence on digital technologies has increased in our industry, cyber incidents, including deliberate attacks and unintentional events, have also increased. Our systems and infrastructure are, and those of our business partners, including vendors, service providers, operating partners, purchasers of our production and financial institutions may be, subject to damage or interruption from a number of potential sources including natural disasters, software viruses or other malware, power failures, cyber-attacks and other events. We and our business partners also face various other cyber-security threats from criminal hackers, state-sponsored intrusion, industrial espionage and employee malfeasance, including threats to gain access to sensitive information or to render data or systems unusable.

Our technologies, systems and networks, and those of our business partners, may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, theft of property or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Although we have not suffered material losses related to cyber-attacks to date, if we were successfully attacked, we could incur substantial remediation and other costs or suffer other negative consequences, such as a loss of competitive information, critical infrastructure, personnel or capabilities essential to our operations. Events of this nature could have a material adverse effect on our reputation, financial condition, results of operations or cash flows. Moreover, as the sophistication of cyber-attacks continues to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities.

The physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

Many scientists believe that increasing concentrations of carbon dioxide, methane and other GHGs in the Earth's atmosphere are changing global climate patterns. One consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such events were to occur, or become more frequent, our operations could be adversely affected in various ways, including through damage to our facilities or from increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. As a result, if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Risks Relating to Financial Matters

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our production and reserves, and ultimately our profitability. Lender hesitancy to offer financing to our industry may increase this risk.

Our industry is capital intensive. We expect to continue to make substantial capital expenditures for the exploration, development, production and acquisition of crude oil, natural gas and NGL reserves. To date, we have financed capital expenditures primarily with bank borrowings under our revolving credit facility, cash generated from operations and proceeds from capital markets transactions and the sale of properties. We intend to finance our future capital expenditures utilizing similar financing sources. Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of crude oil, natural gas and NGLs we are able to produce from existing wells;
- the prices at which crude oil, natural gas and NGLs are sold;
- the costs to produce crude oil, natural gas and NGLs; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower commodity prices, operating difficulties or for any other reason, our need for capital from other sources could increase, and there can be no assurance that such other sources of capital would be available at that time on reasonable terms or at all. If we raise funds by issuing additional equity securities, this would have a dilutive effect on existing shareholders. If we raise funds through the incurrence of debt, the risks we face with respect to our indebtedness would increase and we would incur additional interest expense.

Additionally, due to recent default rates in the oil and gas industry and other factors, some lenders have expressed a hesitancy to lend to oil and gas producers, and may require terms less favorable to the producers or, in some cases, may refuse to provide financing to the industry altogether. We anticipate that the number of lenders willing to participate in the lending syndicate under our revolving credit facility may decline in the future. Our inability to obtain sufficient financing on acceptable terms would adversely affect our financial condition and profitability.

We have a substantial amount of debt and the cost of servicing, and risks related to refinancing, that debt could adversely affect our business. Those risks could increase if we incur more debt.

We have a substantial amount of indebtedness outstanding. As a result, a significant portion of our cash flows will be required to pay interest and principal on our indebtedness, and we may not generate sufficient cash flows from operations, or have future borrowing capacity available, to enable us to repay our indebtedness or to fund other liquidity needs.

Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash. Our cash flow from operating activities and other sources may not be sufficient to fund our liquidity needs. Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend on our future operating performance, our financial condition and the availability of refinancing indebtedness, which will be affected by prevailing economic conditions and financial, business and other factors, many of which are beyond our control. We cannot assure you that our business will generate sufficient cash flow from operations, or that sufficient future borrowings will be available to us under our revolving credit facility or otherwise, to fund our liquidity needs.

A substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including by curtailing our exploration and drilling programs, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing. In addition, we might be required to dispose of material assets or operations to meet our debt service and other obligations. We may not be able to consummate these dispositions for fair market value, in a timely manner or at all. Furthermore, any proceeds that we could realize from any dispositions may not be adequate to meet our debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of our debt agreements could restrict us from implementing some of these alternatives.

Covenants in our debt agreements currently impose, and future financing agreements may impose, significant operating and financial restrictions.

Our current debt agreements contain restrictions, and future financing agreements may contain additional restrictions, on our activities, including covenants that restrict our and our restricted subsidiaries' ability to:

- incur additional debt;
- pay dividends on, redeem or repurchase stock;
- create liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sale and leaseback transactions;
- merge or consolidate;
- restrict dividends or other payments from restricted subsidiaries;
- sell equity interests of restricted subsidiaries; and
- sell, assign, transfer, lease, convey or dispose of assets.

Our revolving credit facility is secured by substantially all of our oil and gas properties as well as a pledge of all ownership interests in our operating subsidiaries. The restrictions contained in our debt agreements may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We may also incur future debt obligations that subject us to additional restrictive covenants.

Our revolving credit facility has substantial restrictions and financial covenants and our ability to comply with those restrictions and covenants is uncertain. Our lenders can unilaterally reduce our borrowing availability based on anticipated commodity prices.

We expect to depend on our revolving credit facility for part of our future capital needs. Our ability to comply with covenants and restrictions in our credit agreement in the future is uncertain and will be affected by the levels of cash flows from operations and events or circumstances beyond our control. Our failure to comply with any of these restrictions and covenants could result in a default under our credit agreement, and cause all of our existing indebtedness to become immediately due and payable.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based upon projected revenues from the properties securing their loan. Decreases in the price of crude oil, natural gas or NGLs can be expected to have an adverse effect on the borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Outstanding borrowings in excess of the borrowing base must be repaid immediately unless we pledge other crude oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility. Our inability to borrow additional funds under our revolving credit facility could adversely affect our operations and our financial results.

If we are unable to comply with the restrictions and covenants in our debt agreements, the resulting default could lead to an acceleration of payment of funds that we have borrowed and we may not have or be able to obtain the funds necessary to repay those amounts.

Any default under the agreements governing our indebtedness, including a default under our revolving credit facility that is not waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal and interest on our indebtedness and satisfy our other obligations. If we are unable to generate sufficient cash flows and are otherwise unable to obtain the funds necessary to meet required payments of principal and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness.

In the event of such a default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. In addition, the default could result in a cross-default under other debt agreements. If our operating performance declines, we may in the future need to seek waivers from the required lenders under our revolving credit facility to avoid being in default and we may not be able to obtain such a waiver. If this occurs and no waiver is obtained, we would be in default under our revolving credit facility, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. We cannot assure you that we will be granted waivers or amendments to our debt agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all.

We may be adversely affected by the phaseout of the London Interbank Offered Rate ("LIBOR") or the replacement of LIBOR with a different reference rate.

On July 27, 2017, the Financial Conduct Authority (the authority that regulates LIBOR) announced that it would phase out LIBOR by the end of 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is in the process of assessing replacing U.S. dollar LIBOR with a newly created index (e.g. secured overnight financing rate). Changes in the method of calculating LIBOR, or the replacement of LIBOR with an alternative rate or benchmark, may adversely affect interest rates and result in higher borrowing costs. This could materially and adversely affect our results of operations, cash flows and liquidity. It is not possible to predict the effect of these changes or the establishment of alternative reference rates in the United States or elsewhere.

Our commodity derivative activities could result in financial losses or reduced income from failure to perform by our counterparties, could limit our potential gains from increases in prices and could result in volatility in our net income.

We use commodity derivatives for a portion of the production from our own wells to achieve more predictable cash flows, to reduce exposure to adverse fluctuations in commodity prices, and to allow our natural gas marketing company to offer pricing options to natural gas sellers and purchasers. These arrangements expose us to the risk of financial loss in some circumstances, including when purchases or sales are different than expected or the counterparty to the commodity derivative contract defaults on its contractual obligations. In addition, many of our commodity derivative contracts are based on WTI or another crude oil or natural gas index price. The risk that the differential between the index price and the price we receive for the relevant production may change unexpectedly makes it more difficult to hedge effectively and increases the risk of a hedging-related loss. Also, commodity derivative arrangements may limit the benefit we would otherwise receive from increases in the prices for the relevant commodity.

At December 31, 2020, we had hedged a total of 20.0 MMBbls crude oil and 120.5 MMBtu of natural gas for 2021 and 2022. These hedges may be inadequate to protect us from continuing and prolonged declines in crude oil and natural gas prices.

Since we do not designate our commodity derivatives as cash flow hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of commodity derivatives are recorded in our income statements and our net income is subject to greater volatility than it would be if our commodity derivative instruments qualified for hedge accounting. For instance, if commodity prices rise significantly, this could result in significant non-cash charges during the relevant period, which could have a material negative effect on our net income.

Our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The occurrence of a significant accident or other event that is not fully covered by insurance, not properly or timely noticed to our carrier, or that is in excess of our insurance coverage, could have a material adverse effect on our operations and financial condition. Insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. In addition, pollution and environmental risks are generally not fully insurable. The cost of obtaining insurance has increased as a result of the SRC Acquisition because of the increased size of our asset base.

The price of our common stock has been and may continue to be highly volatile, which may make it difficult for shareholders to sell our common stock when desired or at attractive prices.

The market price of our common stock is highly volatile and we expect it to continue to be volatile for the foreseeable future. Adverse events including changes in production volumes, worldwide demand and prices for crude oil and natural gas, regulatory developments, and changes in securities analysts' estimates of our financial performance could negatively impact the market price of our common stock. General market conditions, including the level of, and fluctuations in, the trading prices of stocks generally could also have a similar negative impact. The stock markets regularly experience price and volume volatility that affects many companies' stock prices without regard to the operating performance of those companies. Volatility of this type may affect the trading price of our common stock. Similar factors could also affect the trading prices of our senior notes.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in *Note 12 - Commitments and Contingencies - Litigation and Legal Items* included in *Item 8. Financial Statements and Supplementary Data* to our consolidated financial statements included elsewhere in this report.

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

Our common stock, par value $0.01 per share, is traded on the NASDAQ Global Select Market under the symbol "PDCE."

As of February 16, 2021, we had approximately 430 stockholders of record.

While we have not declared any cash dividends on our common stock, our board of directors recently approved a quarterly dividend program expected to commence mid-2021. The dividend program and payment of any future dividends thereunder will be made at the discretion of our board of directors and will depend on our results of operations, cash flows, financial position and capital requirements, as well as general business conditions, legal, tax and regulatory restrictions and other factors our board of directors deems relevant at the time it determines to declare such dividends.

Additionally, our revolving credit facility, as well as the indentures governing our 6.125% senior notes due 2024 (the "2024 Senior Notes"), 2025 Senior Notes and 2026 Senior Notes, the terms of which are summarized in *Note 9 - Long-term Debt* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report, include restrictions based on our leverage and other certain financial metrics that could impact our ability to pay cash dividends. As we declare dividends in the future, we will monitor compliance with such restrictions.

The following table presents information about our purchases of our common stock during the year ended December 31, 2020:

Period	Total Number of Shares Purchased (1) (3)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs *(in millions)*
January (2)	485,948	$ 23.72	217,500	$ 366.0
February	585,455	20.95	552,500	354.5
March	500,782	15.41	496,000	346.8
April	49,064	6.29	—	346.8
May	14,134	11.27	—	346.8
June	1,021	16.02	—	346.8
July	6,902	13.34	—	346.8
August	6,619	14.80	—	346.8
September	3,121	13.26	—	346.8
October	68,112	13.28	—	346.8
November	1,209	15.06	—	346.8
December	628	18.40	—	346.8
Total purchases	1,722,995	$ 19.25	1,266,000	$ 346.8

(1) In April 2019, the board of directors approved a program to acquire up to $200.0 million of our outstanding common stock and in August 2019, effective with the closing of the SRC Acquisition, increased such amount to $525.0 million (the "Stock Repurchase Program"). The Stock Repurchase Program does not require any specific number of shares to be acquired, and can be modified or discontinued by the board of directors at any time. We reinstated our Stock Repurchase Program in late February 2021. Repurchases may extend until December 31, 2023.

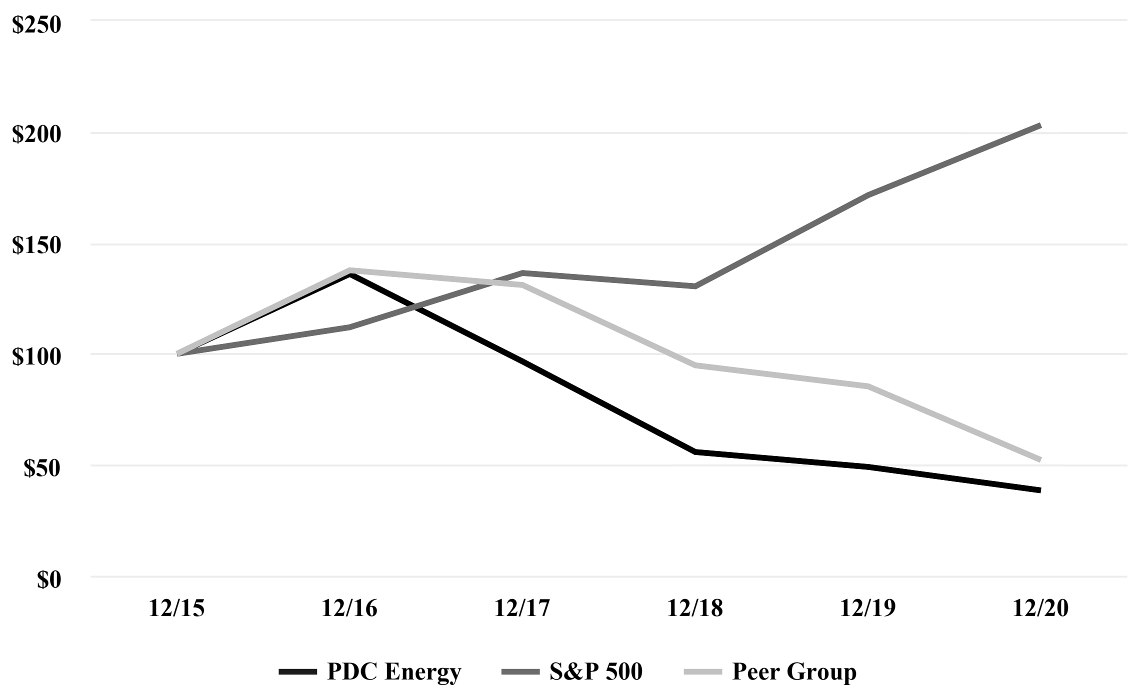
(2) In January 2020, we merged with SRC, and upon closing, issued approximately 38.9 million shares of our common stock to SRC shareholders. Of the issued shares, 244,333 shares were withheld in lieu of tax liabilities related to the issuance of the stock.

(3) Purchases outside of the Stock Repurchase Program and not in connection with the SRC Acquisition represent shares withheld from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans. The withheld shares are not considered common stock repurchased under the Stock Repurchase Program.

Stockholder Performance Graph

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2020 with the cumulative total returns for the same period for the Standard and Poor's ("S&P") 500 Index and the Standard Industrial Code ("SIC") Index. The SIC Index is a weighted composite of 196 crude petroleum and natural gas companies. The cumulative total stockholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2015, and in the S&P 500 Index and the SIC Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
Among PDC Energy, Inc., the S&P 500 Index, and a Peer Group



	12/15	12/16	12/17	12/18	12/19	12/20
PDC Energy	100.00	135.97	96.55	55.75	49.03	38.46
S&P 500	100.00	111.96	136.4	130.42	171.49	203.04
Peer Group	100.00	137.64	131.01	94.81	85.35	52.16

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below should be read in conjunction with *Item* 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* and *Item 8. Financial Statements and Supplementary Data* of this report.

	Year Ended/As of December 31,				
	2020 (1)	2019	2018	2017	2016
	(in millions, except per share data and as noted)				
Statement of Operations:					
Crude oil, natural gas and NGLs sales	$ 1,152.6	$ 1,307.3	$ 1,390.0	$ 913.1	$ 497.4
Commodity price risk management gain (loss), net	180.3	(162.8)	145.2	(3.9)	(125.7)
Total revenues	1,339.2	1,156.1	1,548.7	921.6	382.9
Net income (loss)	(724.3)	(56.7)	2.0	(127.5)	(245.9)
Earnings (loss) per share:					
Basic	$ (7.37)	$ (0.89)	$ 0.03	$ (1.94)	$ (5.01)
Diluted	(7.37)	(0.89)	0.03	(1.94)	(5.01)
Statement of Cash Flows:					
Net cash flows from:					
Operating activities	$ 870.1	$ 858.2	$ 889.3	$ 597.8	$ 486.3
Investing activities	(687.2)	(677.8)	(1,087.9)	(717.0)	(1,509.1)
Financing activities	(181.3)	(188.9)	18.1	65.0	1,266.1
Capital expenditures for development of crude oil and natural gas properties	(551.0)	(855.9)	(946.4)	(737.2)	(436.9)
Acquisition of crude oil and natural gas properties	(139.8)	(13.2)	(180.0)	(15.6)	(1,073.7)
Balance Sheet:					
Total assets	$ 5,238.0	$ 4,448.7	$ 4,544.1	$ 4,420.4	$ 4,485.8
Working capital (deficit)	(471.6)	(57.2)	(166.6)	(16.4)	129.2
Total debt, net of unamortized discount and debt issuance costs	1,602.6	1,177.2	1,194.9	1,151.9	1,044.0
Total stockholders' equity	2,615.5	2,335.5	2,526.7	2,507.6	2,622.8
Average Pricing and Production Expenses (per Boe and as a percent of sales for production taxes):					
Sales price (excluding net settlements on derivatives)	$ 16.86	$ 26.46	$ 34.61	$ 28.69	$ 22.43
Lease operating expenses	2.36	2.88	3.26	2.82	2.70
Production taxes	0.87	1.63	2.25	1.91	1.42
Production taxes (as a percent of sales)	5.2 %	6.2 %	6.5 %	6.6 %	6.3 %
Transportation, gathering and processing	1.14	0.94	0.93	1.04	0.83
Total production	68,368	49,414	40,160	31,830	22,176
Total proved reserves (MMBoe)	731.1	610.9	544.9	452.9	341.4

(1) In 2020, we closed the SRC Acquisition for aggregate consideration of approximately $1.2 billion.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in *Item 8. Financial Statements and Supplementary Data* and also with *Item 1A. Risk Factors* of this report. A discussion of changes in our results of operations from 2018 to 2019 has been omitted from this report but may be found in *Item 7. Management's Discussion and Analysis*, of our Annual Report on Form 10-K for the year ended December 31, 2019, filed with the SEC on February 27, 2020. Further, we encourage you to review the *Special Note Regarding Forward-Looking Statements* in Part I of this report.

EXECUTIVE SUMMARY

2020 Financial Overview of Operations and Liquidity

COVID-19 Impact

During 2020, the effects of the coronavirus 2019 ("COVID-19") pandemic led to a significant decline in global demand for crude oil and natural gas, contributing to a drastic reduction in commodity prices and negatively impacting oil and natural gas producers located in the United States, including PDC. The commodity price environment may remain volatile for an extended period as a result of reduced global oil and natural gas demand and the global economic recession. We expect to be able to fund our operations, planned capital expenditures, working capital and other requirements during the next 12 months and for the foreseeable future. See *Item 1A. Risk Factors* for additional information regarding the potential impacts of the COVID-19 pandemic.

Financial Matters

Production volumes increased 38 percent to 68.4 MMBoe in 2020 compared to 2019. The majority of the increase is attributed to producing properties acquired in the SRC Acquisition. Total liquids production of crude oil and NGLs comprised 60 percent of production in 2020. For the month ended December 31, 2020, we maintained an average production rate of approximately 178,000 Boe per day, up from approximately 139,000 Boe per day for the month ended December 31, 2019.

Crude oil, natural gas and NGLs sales revenue decreased to $1.2 billion in 2020 compared to $1.3 billion in 2019, driven by a 36 percent decrease in weighted-average realized commodity prices, partially offset by the 38 percent increase in production.

We had positive net settlements from commodity derivative contracts of $279.3 million for 2020 as compared to negative net settlements of $17.6 million for 2019.

The combined revenue from crude oil, natural gas and NGLs sales and net settlements received on our commodity derivative instruments was $1.4 billion in 2020 and $1.3 billion in 2019.

In 2020, we generated a net loss of $724.3 million or, $7.37 per diluted share, compared to net loss of $56.7 million, or $0.89 per diluted share, in 2019. Our net loss for the year ended December 31, 2020 as compared to December 31, 2019 was most significantly impacted by the increase in impairment of properties and equipment and the decrease in crude oil, natural gas and NGLs sales, partially offset by the net commodity price risk management gain.

Adjusted EBITDAX, a non-U.S. GAAP financial measure, was $990.6 million and $882.7 million, in 2020 and 2019, respectively. Cash flows from operations were $870.1 million and $858.2 million in 2020 and 2019, respectively, and adjusted cash flows from operations, a non-U.S. GAAP financial measure, were $921.6 million and $825.4 million, respectively. Adjusted free cash flow, a non-U.S. GAAP financial measure, was $399.3 million for 2020 as compared to $37.7 million for 2019.

See *Reconciliation of Non-U.S. GAAP Financial Measures* below for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

SRC Acquisition

In January 2020, we merged with SRC in a transaction valued at $1.7 billion, inclusive of SRC's net debt. Upon closing, we issued approximately 38.9 million shares of our common stock to SRC shareholders and holders of SRC equity awards, reflecting the issuance of 0.158 of a share of our common stock in exchange for each share of SRC common stock and the cancellation of outstanding SRC equity awards pursuant to the Merger Agreement.

Liquidity

Available liquidity as of December 31, 2020 was $1.4 billion, which was comprised of $2.6 million of cash and cash equivalents and $1.4 billion available for borrowing under our revolving credit facility. In September 2020, we issued an additional $150.0 million principal amount of 2026 Senior Notes. The net proceeds from the offering were used to repay a portion of the amount outstanding under our revolving credit facility. In October 2020, as part of our fall 2020 semi-annual redetermination, the borrowing base of our credit facility was reduced from $1.7 billion to $1.6 billion, with a corresponding automatic reduction of our elected commitment level to $1.6 billion. Looking into 2021, based on our expected cash flows from operations, our cash and cash equivalents and availability under our revolving credit facility, we believe that we will have sufficient capital available to repay our 2021 Convertible Notes, which mature in September 2021, and to fund our planned activities through the 12-month period following the filing of this report. We exited 2020 with a debt balance of $1.6 billion.

Stock Repurchase Program

As previously noted, our board of directors has approved a Stock Repurchase Program of $525 million, of which approximately $346.8 million remains available. We suspended the program in March 2020 but recently reinstated it in light of our reduced level of indebtedness. The program may extend until December 31, 2023.

Drilling and Completion Overview

We ran three drilling rigs in the Wattenberg Field through the middle of April 2020, when we dropped to a two-rig pace. We released a second rig at the end of May 2020 and continued at a one-rig pace for the remainder of the year. We also released our only completion crew in the Wattenberg Field in early May 2020 but resumed completion activities in September 2020. In the Delaware Basin, we ran one drilling rig through early May 2020 and we released our only active completion crew in March 2020. We did not have material activity in the Delaware Basin for the remainder of 2020. Our total 2020 capital investments in crude oil and natural gas properties was $522.3 million.

The following tables summarize our drilling and completion activity for the year ended December 31, 2020:

	Operated Wells					
	Wattenberg Field		Delaware Basin (1)		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2019	145	134.3	30	29.1	175	163.4
Wells spud	105	99.3	3	2.9	108	102.2
Acquired in-process (2)	88	84.7	—	—	88	84.7
Wells turned-in-line	(124)	(116.5)	(13)	(13.0)	(137)	(129.5)
In-process as of December 31, 2020	214	201.8	20	19.0	234	220.8

(1) In the Delaware Basin, we had eight operated batch drilled wells that were spud in late December 2019 with final laterals being reached in early 2020.
(2) Represents in-process wells and wells being completed that we received as part of the SRC Acquisition.

Our in-process wells represent wells that are in the process of being drilled or have been drilled and are waiting to be fractured and/or for gas pipeline connection. Our in-process wells are generally completed and turned-in-line within two years of drilling.

2021 Operational and Financial Outlook

We anticipate that our total production for 2021 will range between 190,000 Boe to 200,000 Boe per day, approximately 64,000 Bbls to 68,000 Bbls of which are expected to be crude oil. Our planned 2021 capital investments in crude oil and natural gas properties, which we expect to be between $500 million and $600 million, are focused on continued execution of our development plans in the Wattenberg Field and the Delaware Basin.

We believe that we maintain a degree of operational flexibility to control the pace of our capital spending. As we execute our capital investment program, we continually monitor, among other things, expected rates of return, the political environment and our remaining inventory in order to best meet our short- and long-term corporate strategy. We may revise our 2021 capital investment program during the year as a result of, among other things, changes in commodity prices or our internal long-term outlook for commodity prices, requirements to hold acreage, the cost of services for drilling and well completion activities, drilling results, changes in our borrowing capacity, a significant change in cash flows, regulatory issues, requirements to maintain continuous activity on leaseholds or acquisition and/or divestiture opportunities.

Wattenberg Field. We are drilling in the horizontal Niobrara and Codell plays in the rural areas of the core Wattenberg Field, which is further delineated between the Kersey, Prairie, Plains, and Summit development areas. Our 2021 capital investment program for the Wattenberg Field is approximately 75 percent of our expected total capital investments in crude oil and natural gas properties, of which approximately 90 percent is expected to be invested in operated drilling and completion activity. In 2021, we plan to drill standard-reach lateral ("SRL"), mid-reach lateral (“MRL”) and extended-reach lateral (“XRL”) wells in the Wattenberg Field. In 2021, we anticipate spudding approximately 75 to 85 operated wells and turning-in-line approximately 150 to 175 operated wells. As of December 31, 2020, we have approximately 214 gross operated DUCs and 300 approved permitted locations. In 2021,we expect to operate with one full-time horizontal rig and completion crew along with a part-time spudder rig. Our program is expected to have an average development cost per well between $2.5 million and $3.6 million, depending upon the lateral length of the well. The remainder of the Wattenberg Field capital investment program is expected to be used for land, capital workovers, facilities projects and non-operated drilling.

Delaware Basin. Total capital investments in crude oil and natural gas properties in the Delaware Basin for 2021 are expected to be approximately 25 percent of our total capital investments, of which approximately 90 percent is expected to be invested in operated drilling and completion activity. In 2021, we anticipate spudding and turning-in-line approximately 15 to 20 operated wells. The majority of the wells we plan to drill in 2021 in the Delaware Basin are MRL and XRL wells. We expect to drill at a one-rig pace in 2021 along with a completion crew for four months starting towards the end of the first quarter, with an average development costs per well between $6.7 million and $8.0 million for MRL and XRL wells, depending upon the lateral length of the well.

We are committed to our disciplined approach to managing our development plans. Based on our current production forecast for 2021 and assumed average NYMEX prices of $45.00 per Bbl of crude oil and $2.50 per Mcf of natural gas and an assumed average composite price of $12.00 per Bbl for NGLs, we expect 2021 cash flows from operations to exceed our capital investments in crude oil and natural gas properties. Any excess cash flows from operations will be used towards reducing our indebtedness as well as returning capital to our shareholders.

Colorado Political Update

Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have historically advanced various alternatives for ballot initiatives which would result in significantly limiting or preventing oil and natural gas development in the state. Senate Bill 19-181 ("SB19-181") was enacted by the Colorado legislature in 2019 to address concerns underlying the ballot initiatives. The COGCC conducted a series of rulemaking hearings pursuant to SB 19-181 during 2020 which resulted in updated regulatory and permitting requirements, including setbacks and siting requirements. The COGCC commissioners determined that locations with residential or high occupancy building units, schools or child care facilities within 2,000 feet would be subject to additional siting requirements, but also supported “off ramps” allowing oil and gas operators to site their drill pads as close as 500 feet from residential or high occupancy building units (excluding schools and child care facilities) in certain circumstances. The 2020 rulemaking hearings also resulted in the adoption of a number of other new regulatory requirements, including requirements regarding permitting, cumulative and surface impacts, asset transfers, venting and flaring, and remediation. However, third-party proposals which were presented to the COGCC prohibit or dramatically restrict oil and gas development were not adopted by the Commissioners. Governor Polis has publicly stated his opposition to further ballot initiatives in 2022 while rulemaking under SB 19-181 is in process and has acknowledged the importance of regulatory certainty.

It is nevertheless possible that future ballot initiatives will be proposed that would dramatically limit the areas of the state in which drilling would be permitted to occur. See *Part I, Item1A. Risk Factors- Relating to Our Business and the*

Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.

Results of Operations

Summary of Operating Results

The following table presents selected information regarding our operating results:

	Year Ended December 31,				
				Percent Change	
	2020	2019	2018	2020-2019	2019-2018
	(dollars in millions, except per unit data)				
Production:					
Crude oil (MBbls)	23,720	19,166	16,963	24 %	13 %
Natural gas (MMcf)	165,637	115,950	88,017	43 %	32 %
NGLs (MBbls)	17,042	10,923	8,527	56 %	28 %
Crude oil equivalent (MBoe)	68,368	49,414	40,160	38 %	23 %
Average Boe per day (Boe)	186,798	135,381	110,027	38 %	23 %
Crude Oil, Natural Gas and NGLs Sales:					
Crude oil	$ 816.8	$ 1,020.7	$ 1,038.0	(20)%	(2)%
Natural gas	178.8	151.0	163.2	18 %	(7)%
NGLs	157.0	135.6	188.8	16 %	(28)%
Total crude oil, natural gas and NGLs sales	$ 1,152.6	$ 1,307.3	$ 1,390.0	(12)%	(6)%
Net Settlements on Commodity Derivatives:					
Crude oil	294.4	(18.3)	(124.4)	*	(85)%
Natural gas	(15.1)	0.7	13.9	*	(95)%
NGLs	—	—	(5.0)	*	*
Total net settlements on derivatives	279.3	(17.6)	(115.5)	*	(85)%
Average Sales Price (excluding net settlements on derivatives):					
Crude oil (per Bbl)	$ 34.44	$ 53.26	$ 61.19	(35)%	(13)%
Natural gas (per Mcf)	1.08	1.30	1.85	(17)%	(30)%
NGLs (per Bbl)	9.21	12.41	22.14	(26)%	(44)%
Crude oil equivalent (per Boe)	16.86	26.46	34.61	(36)%	(24)%
Average Costs and Expenses (per Boe):					
Lease operating expenses	$ 2.36	$ 2.88	$ 3.26	(18)%	(12)%
Production taxes	0.87	1.63	2.25	(47)%	(28)%
Transportation, gathering and processing expenses	1.14	0.94	0.93	21 %	1 %
General and administrative expense	2.36	3.27	4.25	(28)%	(23)%
Depreciation, depletion and amortization	9.06	13.04	13.94	(31)%	(6)%
Lease Operating Expenses by Operating Region (per Boe):					
Wattenberg Field	$ 2.15	$ 2.50	$ 2.99	(14)%	(16)%
Delaware Basin	3.48	4.15	4.14	(16)%	— %
Utica Shale [(1)]	—	—	3.46	*	*

* *Percent change is not meaningful.*

(1) *In March 2018, we completed the disposition of our Utica Shale properties.*

Crude Oil, Natural Gas and NGLs Sales

Crude oil, natural gas and NGLs sales revenue for the year ended December 31, 2020 decreased compared to the year ended December 31, 2019 due to the following:

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in millions)	
Change in:		
Production	$ 383.2	$ 239.6
Average crude oil price	(446.4)	(152.0)
Average natural gas price	(37.0)	(64.0)
Average NGLs price	(54.5)	(106.3)
Total change in crude oil, natural gas and NGLs sales revenue	$ (154.7)	$ (82.7)

Crude Oil, Natural Gas and NGLs Production

The following table presents crude oil, natural gas and NGLs production.

	Year Ended December 31,			Percent Change	
Production by Operating Region	**2020**	**2019**	**2018**	**2020-2019**	**2019-2018**
Crude oil (MBbls)					
Wattenberg Field	19,552	14,489	12,809	35 %	13 %
Delaware Basin	4,168	4,677	4,108	(11)%	14 %
Utica Shale (1)	—	—	46	*	*
Total	23,720	19,166	16,963	24 %	13 %
Natural gas (MMcf)					
Wattenberg Field	140,845	91,785	68,326	53 %	34 %
Delaware Basin	24,792	24,165	19,277	3 %	25 %
Utica Shale (1)	—	—	414	*	*
Total	165,637	115,950	88,017	43 %	32 %
NGLs (MBbls)					
Wattenberg Field	14,495	8,198	6,455	77 %	27 %
Delaware Basin	2,547	2,725	2,038	(7)%	34 %
Utica Shale (1)	—	—	34	*	*
Total	17,042	10,923	8,527	56 %	28 %
Crude oil equivalent (MBoe)					
Wattenberg Field	57,521	37,984	30,652	51 %	24 %
Delaware Basin	10,847	11,430	9,359	(5)%	22 %
Utica Shale (1)	—	—	149	*	*
Total	68,368	49,414	40,160	38 %	23 %
Average crude oil equivalent per day (Boe)					
Wattenberg Field	157,161	104,066	83,978	51 %	24 %
Delaware Basin	29,637	31,315	25,641	(5)%	22 %
Utica Shale (1)	—	—	408	*	*
Total	186,798	135,381	110,027	38 %	23 %

* *Percent change is not meaningful.*

(1) *In March 2018, we completed the disposition of our Utica Shale properties.*

Net production volumes for oil, natural gas and NGLs increased 38% during 2020 compared to 2019. The overall production increase between periods was primarily due to producing properties acquired in the SRC Acquisition, which added approximately 19.7 MMBoe of incremental production in 2020, and wells turned-in-line during 2020. These volume increases were partially offset by normal field production declines across our existing wells.

The following table presents our crude oil, natural gas and NGLs production ratio by operating region:

	Year Ended December 31,		
Production Ratio by Operating Region	**2020**	**2019**	**2018**
Wattenberg Field			
Crude oil	34 %	38 %	42 %
Natural gas	41 %	40 %	37 %
NGLs	25 %	22 %	21 %
Total	100 %	100 %	100 %
Delaware Basin			
Crude oil	38 %	41 %	44 %
Natural gas	38 %	35 %	34 %
NGLs	24 %	24 %	22 %
Total	100 %	100 %	100 %
Utica Shale (1)			
Crude oil	— %	— %	31 %
Natural gas	— %	— %	46 %
NGLs	— %	— %	23 %
Total	— %	— %	100 %

(1) In March 2018, we completed the disposition of our Utica Shale properties.

Midstream Capacity

Our ability to market our production depends substantially on the availability, proximity and capacity of in-field gathering systems, compression and processing facilities, as well as transportation pipelines out of the basin, all of which are owned and operated by third parties. If adequate midstream facilities and services are not available on a timely basis and at acceptable costs, our production and results of operations could be adversely affected. In response to the substantial development drilling in our current areas of operation in recent years, third-party midstream providers have significantly expanded their midstream facilities and services. These third-party midstream facility expansions, in conjunction with the more recent slowdown in producer activity, have provided for improved and more stabilized line pressures and a production environment that is more favorable for producers, both currently and for the near term given anticipated producer activity levels.

The ultimate timing and availability of adequate infrastructure remains out of our control. Weather, regulatory developments and other factors also affect the adequacy of midstream infrastructure. Like other producers, from time to time we enter into volume commitments with midstream providers in order to incentivize them to provide increased capacity to sufficiently meet our projected volume growth from our areas of operation. If our production falls below the level required under these agreements, we could be subject to transportation charges or aid in construction payments for commitment shortfalls.

Wattenberg Field. Beginning in the mid-fourth quarter of 2019 and continuing through the fourth quarter of 2020, the combination of DCP Midstream, LP's ("DCP") continued system expansions and the availability of both residue gas and NGL takeaway out of the basin allowed us to experience reduced line pressures for all of our operated areas of the Wattenberg Field. Given current and forecasted activity levels in the basin, we anticipate that this expansion will provide ample processing capacity to accommodate our future operated production.

Our production in the Wattenberg Field is significantly dependent on DCP's gathering system, and this reliance increased considerably when we closed the SRC Acquisition. We continue to work with our midstream service providers in an effort to ensure all of the existing in-basin infrastructure is fully utilized and that all options for system expansion are evaluated and implemented to the extent possible to accommodate projected future volume growth from the field.

As midstream infrastructure development and upstream capital discipline continues, we anticipate having the ability to move additional volumes on DCP's system in the long-term. The successful and timely completion of incremental development projects depends on continued capital investment by midstream providers, which could be impacted during times of challenging market conditions.

Delaware Basin. Our production from the Delaware Basin was not materially affected by midstream or downstream capacity constraints during the year ended December 31, 2020. Similar to the Wattenberg Field, our crude oil netback pricing realizations were most negatively impacted by the demand reduction that resulted from COVID-19.

Pipeline utilization in the Permian Basin has fallen from the constrained levels experienced during the first quarter of 2020. The COVID-19-induced downturn also forced widespread curtailments in natural gas production, which lowered pipeline utilization and eventually improved pricing differentials in the basin during the remainder of 2020. The completion of Kinder Morgan's Permian Highway Pipeline occurred in the fourth quarter of 2020 and provides additional takeaway capacity out of the Permian Basin. A portion of our natural gas production is committed to the use of this pipeline starting in January 2021.

Crude Oil, Natural Gas and NGLs Pricing

Our results of operations depend upon many factors. Key factors include market prices of crude oil, natural gas and NGLs and our ability to market our production effectively. Crude oil, natural gas and NGLs prices have a high degree of volatility and our realizations can change substantially. Our realized sales prices for crude oil, natural gas and NGLs decreased 36 percent during 2020 as compared to 2019. The NYMEX average daily crude oil and NYMEX first-of-the-month natural gas prices decreased 31 percent and 21 percent, respectively, as compared to 2019. The decreases were primarily due to the effects of the COVID-19 pandemic, geopolitical conditions and supply disruptions.

The following table presents weighted-average sales prices of crude oil, natural gas and NGLs for the periods presented:

Weighted-Average Realized Sales Price by Operating Region *(excluding net settlements on derivatives)*	**Year Ended December 31,** 2020	2019	2018	**Percent Change** 2020-2019	2019-2018
Crude oil (per Bbl)					
Wattenberg Field	$ 34.21	$ 52.99	$ 61.14	(35)%	(13)%
Delaware Basin	35.48	54.08	61.37	(34)%	(12)%
Utica Shale (1)	—	—	58.10	*	*
Weighted-average price	34.44	53.26	61.19	(35)%	(13)%
Natural gas (per Mcf)					
Wattenberg Field	1.22	1.49	1.90	(18)%	(22)%
Delaware Basin	0.28	0.57	1.66	(51)%	(66)%
Utica Shale (1)	—	—	2.68	*	*
Weighted-average price	1.08	1.30	1.85	(17)%	(30)%
NGLs (per Bbl)					
Wattenberg Field	8.84	11.51	20.58	(23)%	(44)%
Delaware Basin	11.32	15.12	27.06	(25)%	(44)%
Utica Shale (1)	—	—	24.29	*	*
Weighted-average price	9.21	12.41	22.14	(26)%	(44)%
Crude oil equivalent (per Boe)					
Wattenberg Field	16.84	26.31	34.13	(36)%	(23)%
Delaware Basin	16.94	26.95	36.25	(37)%	(26)%
Utica Shale (1)	—	—	30.98	*	*
Weighted-average price	16.86	26.46	34.61	(36)%	(24)%

* *Percent change is not meaningful.*

(1) In March 2018, we completed the disposition of our Utica Shale properties.

Crude oil, natural gas and NGLs revenues are recognized when we transfer control of crude oil, natural gas or NGLs production to the purchaser. We consider the transfer of control to occur when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from, the crude oil, natural gas or NGLs production. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes delivered and prices received.

Our crude oil, natural gas and NGLs sales are recorded using either the “net-back” or "gross" method of accounting, depending upon the related purchase agreement. We use the net-back method when control of the crude oil, natural gas or NGLs has been transferred to the purchasers of these commodities that are providing transportation, gathering or processing services. In these situations, the purchaser pays us based on a percent of proceeds or a sales price fixed at index less specified deductions. The net-back method results in the recognition of a net sales price that is lower than the index on which the production is based because the operating costs and profit of the midstream facilities are embedded in the net price we are paid. We use the gross method of accounting when control of the crude oil, natural gas or NGLs is not transferred to the purchaser and the purchaser does not provide transportation, gathering or processing services as a function of the price we receive. Rather, we contract separately with midstream providers for the applicable transportation and processing on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering and processing expenses.

Beginning in the second quarter of 2020, COVID-19 led to government restrictions on movement and economic activity, triggering a dramatic reduction in crude oil demand. This negatively impacted crude oil netback pricing realizations, which resulted in meaningful production curtailments during the second quarter of 2020. We expect our realized crude oil prices to be volatile through 2021 due to market uncertainties in crude oil demand as a result of COVID-19.

As discussed above, we enter into agreements for the sale and transportation, gathering and processing of our production, the terms of which can result in variances in the per unit realized prices that we receive for our crude oil, natural gas and NGLs. Information related to the components and classifications in the consolidated statements of operations is shown below. For crude oil, the average NYMEX prices shown below are based on average daily prices throughout each month and, for natural gas, the average NYMEX pricing is based on first-of-the-month index prices, as in each case this is the method used to sell the majority of these commodities pursuant to terms of the relevant sales agreements. For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes. The average realized price both before and after transportation, gathering and processing expenses shown in the table below represents our approximate composite per barrel price for NGLs.

2020	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Realization Percentage Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses	Average Realization Percentage After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 39.40	$ 34.44	87 %	$ 2.34	$ 32.10	81 %
Natural gas (per MMBtu)	2.08	1.08	52 %	0.12	0.96	46 %
NGLs (per Bbl)	39.40	9.21	23 %	—	9.21	23 %
Crude oil equivalent (per Boe)	28.52	16.86	59 %	1.10	15.76	55 %

2019	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Realization Percentage Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses	Average Realization Percentage After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 57.03	$ 53.26	93 %	$ 1.24	$ 52.02	91 %
Natural gas (per MMBtu)	2.63	1.30	49 %	0.17	1.13	43 %
NGLs (per Bbl)	57.03	12.41	22 %	0.10	12.31	22 %
Crude oil equivalent (per Boe)	40.95	26.46	65 %	0.90	25.56	62 %

2018	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Realization Percentage Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses	Average Realization Percentage After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 64.77	$ 61.19	94 %	$ 0.94	$ 60.25	93 %
Natural gas (per MMBtu)	3.09	1.85	60 %	0.22	1.63	53 %
NGLs (per Bbl)	64.77	22.14	34 %	0.21	21.93	34 %
Crude oil equivalent (per Boe)	47.87	34.61	72 %	0.93	33.68	70 %

Our average realization percentages for crude oil decreased in 2020 as compared to 2019, primarily due to higher quantity deducts, larger negative roll realizations and oil storage constraints in the second quarter of 2020, and changes in revenue contracts.

Commodity Price Risk Management

We use commodity derivative instruments to manage fluctuations in crude oil and natural gas prices, including collars, fixed-price exchanges and basis protection exchanges on a portion of our estimated crude oil and natural gas production. For our commodity exchanges, we ultimately realize the fixed price value related to the exchanges. See *Note 6 - Commodity Derivative Financial Instruments* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report for a summary of our derivative positions as of December 31, 2020.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments, and the change in fair value of unsettled commodity derivatives related to our crude oil and natural gas production.

Net settlements of commodity derivative instruments are based on the difference between the crude oil and natural gas index prices at the settlement date of our commodity derivative instruments compared to the respective strike prices contracted for the settlement months that were established at the time we entered into the commodity derivative transaction. The net change in fair value of unsettled commodity derivatives is comprised of the net increase or decrease in the beginning-of-period fair value of commodity derivative instruments that settled during the period and the net change in fair value of unsettled commodity derivatives during the period or from inception of any new contracts entered into during the applicable period. The net change in fair value of unsettled commodity derivatives during the period is primarily related to shifts in the crude oil and natural gas forward price curves and changes in certain differentials.

The following table presents net settlements and net change in fair value of unsettled derivatives included in commodity price risk management, net:

	Year Ended December 31,		
	2020	**2019**	**2018**
		(in millions)	
Commodity price risk management gain (loss), net:			
Net settlements of commodity derivative instruments:			
Crude oil collars and fixed price exchanges	$ 294.4	$ (18.3)	$ (139.7)
Crude oil basis protection exchanges	—	—	15.2
Natural gas collars and fixed price exchanges	(1.4)	8.8	(7.0)
Natural gas basis protection exchanges	(13.7)	(8.1)	21.0
NGLs fixed price exchanges	—	—	(5.0)
Total net settlements of commodity derivative instruments	279.3	(17.6)	(115.5)
Change in fair value of unsettled commodity derivative instruments:			
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	(19.9)	(81.1)	64.9
Crude oil collars and fixed price exchanges	(49.8)	(62.1)	197.0
Natural gas collars and fixed price exchanges	(7.8)	0.1	1.4
Natural gas basis protection exchanges	(21.5)	(2.1)	(2.6)
Net change in fair value of unsettled commodity derivative instruments	(99.0)	(145.2)	260.7
Total commodity price risk management gain (loss), net	$ 180.3	$ (162.8)	$ 145.2

Lease Operating Expenses

Lease operating expenses ("LOE") increased by 13 percent to $161.3 million in 2020 compared to $142.2 million in 2019. The year-over-year increase in LOE is primarily attributable to the wells acquired from our SRC Acquisition in January 2020 and wells turned-in-line during 2020. Specifically, the increase was primarily due to $10.0 million in additional well services, an increase of $2.6 million in produced water disposal, and a $2.7 million increase in non-operated well expenses. The increases were partially offset by operational efficiencies achieved during 2020. LOE per Boe decreased 18 percent to $2.36 in 2020 from $2.88 in 2019, primarily due to a 38 percent increase in production volumes.

Production Taxes

Production taxes are comprised mainly of severance tax and ad valorem tax, and are directly related to crude oil, natural gas and NGLs sales and are generally assessed as a percentage of net revenues. From time to time, there are adjustments to the statutory rates for these taxes based upon certain credits that are determined based upon activity levels and relative commodity prices.

Production taxes decreased 26 percent to $59.4 million in 2020 compared to $80.8 million in 2019, primarily due to the 12 percent decrease in crude oil, natural gas and NGLs sales for 2020 compared to 2019, reductions in effective severance tax rates in the Wattenberg Field and well classifications in the Delaware Basin. Production taxes per Boe decreased 47 percent to $0.87 in 2020 compared to $1.63 in 2019 due to lower realized prices for crude oil, natural gas and NGLs and a 38 percent increase in production volumes between periods.

Transportation, Gathering and Processing Expenses

Transportation, gathering and processing expenses ("TGP") increased 68 percent to $77.8 million in 2020 compared to $46.4 million in 2019, primarily due to higher production volumes between periods as a result of the SRC Acquisition, as well as amendments to existing and new crude oil sales contracts, some of which resulted in a change in recognition from a net-back to a gross presentation of TGP. TGP per Boe increased to $1.14 for 2020 compared to $0.94 for 2019. The increase of TGP per Boe between periods was primarily due to an increase in TGP as discussed above, partially offset by an increase in production volume delivered.

Exploration, Geologic and Geophysical Expense

Geological and geophysical costs decreased 66 percent to $1.4 million in 2020 compared to $4.1 million in 2019, primarily due to costs incurred related to geological and geophysical projects and seismic studies in the Delaware Basin in 2019.

Impairment of Properties and Equipment

The following table sets forth the major components of our impairment of properties and equipment:

	Year Ended December 31,		
	2020	2019	2018
		(in millions)	
Impairment of proved and unproved properties	$ 881.2	$ 10.6	$ 458.4
Impairment of infrastructure and other	1.2	27.9	—
Total impairment of properties and equipment	$ 882.4	$ 38.5	$ 458.4

Impairment Charges. The significant decline in crude oil prices in the first quarter of 2020 was considered a triggering event that required us to assess our crude oil and natural gas properties for possible impairment. As a result of our assessment, we recorded impairment charges of $881.1 million to our proved and unproved properties. Of these impairment charges, approximately $753.0 million was related to our Delaware Basin proved properties. These impairment charges represented the amount by which the carrying value of the crude oil and natural gas properties exceeded the estimated fair value. The estimated fair value was determined based on estimated future discounted net cash flows. In addition to our proved property impairment, we also recognized approximately $127.3 million of impairment charges in the first quarter of 2020 for our unproved properties in the Delaware Basin. These impairment charges were recognized based on a review of our current drilling plans, estimated future cash flows for probable well locations and expected future lease expirations, primarily in areas where we have no development plans. We did not recognize any significant impairment write-downs with respect to our proved and unproved properties during the remainder of 2020. If crude oil prices decline, or we change other estimates impacting future net cash flows (e.g. reserves, price differentials, future operating and/or development costs), our proved and unproved oil and gas properties could be subject to additional impairments in future periods.

General and Administrative Expense

General and administrative expense decreased slightly to $161.1 million in 2020 compared to $161.8 million in 2019. Transaction costs relating to the SRC Acquisition increased from $7.8 million in 2019 to $19.9 million in 2020, and we also incurred $10.2 million of transition expenses relating to the acquisition in 2020. However, these increases were offset by (i) the non-recurrence of certain 2019 expenses including $6.0 million related to shareholder activism, $5.5 million in consultant fees related to business management and ERP implementation and a $3.4 million allowance for royalty owner payments and (ii) a $6.6 million decrease relating to ongoing corporate cost savings initiatives.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. During 2020 and 2019, we invested $522.3 million and $787.7 million, respectively, exclusive of changes in accounts payable related to capital expenditures, in the development of our crude oil and natural gas properties. Depreciation, depletion and amortization expense ("DD&A") related to crude oil and natural gas properties is directly related to proved reserves and production volumes. DD&A expense related to crude oil and natural gas properties was $611.0 million and $638.5 million in 2020 and 2019, respectively.

The year-over-year change in DD&A expense for 2020 compared to 2019 related to crude oil and natural gas properties was primarily due to the following:

		Year Ended December 31, 2020
		(in millions)
Increase in production	$	220.1
Decrease in weighted-average depreciation, depletion and amortization rates		(247.6)
Total decrease in DD&A expense related to crude oil and natural gas properties	$	(27.5)

The following table presents our per Boe DD&A expense rates for crude oil and natural gas properties:

	Year Ended December 31,					
Operating Region/Area	2020		2019		2018	
			(per Boe)			
Wattenberg Field	$	8.80	$	11.77	$	12.58
Delaware Basin		9.68		16.76		17.70
Total weighted-average		8.94		12.92		13.73

The decrease in DD&A expense rate in the Delaware Basin was primarily due to the proved property impairment recognized in the first quarter of 2020, which lowered the carrying value of our depletion base. The effect of this impairment, however, was partially offset by 31.3 MMBoe in net downward revisions to our proved reserves in 2020, which were mainly due to lower SEC reserve pricing and a change in our drilling plan year over year due to the SRC Acquisition.

The decrease in DD&A expense rate in the Wattenberg Field was primarily due to the SRC Acquisition, which added 295 MMBoe in total proved reserves, offset by a $1.6 billion increase in our cost basis.

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $8.7 million for the year ended December 31, 2020, compared to $5.7 million for the year ended December 31, 2019. The increase in depreciation expense between periods was primarily due to our new ERP system which was implemented at the beginning of 2020.

Interest Expense, net

Interest expense, net increased by $17.6 million to $88.7 million in 2020 compared to $71.1 million in 2019. The increase was primarily related to a $9.2 million increase in interest expense related to our revolving credit facility as a result of higher borrowings between periods, a $9.2 million increase related to the assumption of the SRC Senior Notes and a $2.5 million increase related to the issuance of an additional $150 million aggregate principal amount of the 2026 Senior Notes in September 2020. Higher credit facility borrowings in 2020 were primarily due to our payment and termination of SRC's revolving credit facility as well as the partial redemption of the SRC Senior Notes in the first quarter of 2020. The increases in interest expense were offset by a $6.3 million increase in capitalized interest in 2020 as compared to 2019.

Provision for Income Taxes

We recorded an income tax benefit of $7.9 million and $3.3 million for 2020 and 2019, respectively, resulting in effective tax rates of 1.1 percent and 5.5 percent on the respective pre-tax losses. The effective tax rate of 1.1 percent for 2020 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21 percent to the pre-tax loss due to the effect of a full valuation allowance against our deferred income tax assets at December 31, 2020. The effective tax rate of 5.5 percent for 2019 differs from the statutory U.S. federal income tax rate of 21 percent due to state income taxes, non-deductible lobbying expenses, stock-based compensation and non-deductible officers' compensation.

The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At each reporting period, management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies and projected future taxable income in making this assessment. As previously noted, we recorded impairments totaling $882.4 million in 2020. These impairments resulted in three years of cumulative historical pre-tax losses and a net deferred tax asset position. The impairment losses were a key consideration that led us to continue to provide a valuation allowance against our net deferred tax assets as of December 31, 2020 since we cannot conclude that it is more likely than not that our net deferred tax asset will be fully realized in future periods. As a result, we recorded a $7.9 million benefit in 2020 to increase our deferred tax valuation allowance to $165.6 million and reduce the carrying value of our deferred tax assets to zero.

Net Income (Loss)/Adjusted Net Income (Loss)

The factors impacting net losses of $724.3 million and $56.7 million in 2020 and 2019, respectively, are discussed above.

Adjusted net loss, a non-U.S. GAAP financial measure, was $625.3 million and for the year ended December 31, 2020 and adjusted net income, a non-U.S. GAAP financial measure, was $53.3 million for the year ended December 31, 2019. With the exception of the tax-affected (when applicable) net change in fair value of unsettled derivatives, the same factors impacted adjusted net income (loss). See *Reconciliation of Non-U.S. GAAP Financial Measures* below for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

Financial Condition, Liquidity and Capital Resources

Our primary sources of liquidity are cash flows from operating activities, borrowings from our revolving credit facility, asset sales and proceeds raised in debt and equity capital market transactions. In 2020, our net cash flows from operating activities were $870.1 million.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas and NGLs. Fluctuations in our operating cash flows are principally driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile, and we manage a portion of this volatility through our use of commodity derivative instruments. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. Our revolving credit facility imposes limits on the amount of our production we can hedge, and we may choose not to hedge the maximum amounts permitted. Therefore, we may still have fluctuations in our cash flows from operating activities due to the remaining non-hedged portion of our future production.

We may use our available liquidity for operating activities, capital investments, working capital requirements, acquisitions and for general corporate purposes. We maintain a significant capital investment program to execute our development plans, which requires capital expenditures to be made in periods prior to initial production from newly developed wells.

From time to time, these activities may result in a working capital deficit; however, we do not believe that our working capital deficit as of December 31, 2020 is an indication of a lack of liquidity. We had working capital deficits of $471.6 million and $57.2 million at December 31, 2020 and 2019, respectively. The increase was primarily attributable to our 2021 Convertible Notes maturing in September 2021, which resulted in the notes being classified in current liabilities, an increase in the fair value liability of our commodity derivatives and additional current liabilities resulting from the SRC Acquisition. We intend to continue to manage our liquidity position by a variety of means, including through the generation of cash flows from operations, investment in projects with favorable rates of return, protection of cash flows on a portion of our anticipated sales through the use of an active commodity derivative hedging program, utilization of the borrowing capacity under our revolving credit facility and, if warranted, capital markets transactions from time to time.

Our cash and cash equivalents were $2.6 million at December 31, 2020 and availability under our revolving credit facility was $1.4 billion, providing for total liquidity of $1.4 billion as of December 31, 2020. In October 2020, as part of our semi-annual redetermination, the borrowing base of our credit facility was reduced from $1.7 billion to $1.6 billion, with a corresponding reduction of our elected commitment level to $1.6 billion. The borrowing base is primarily based on the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests. Based on our current production forecast for 2021 and assumed average NYMEX prices of $45.00 per Bbl of crude oil and $2.50 per Mcf of natural gas and an assumed average composite price of $12.00 per Bbl for NGLs, we expect 2021 cash flows from operations to exceed our capital investments in crude oil and natural gas properties.

As a result of merging with SRC, we assumed the SRC Senior Notes and paid off and terminated SRC's revolving credit facility. On January 17, 2020, we commenced an offer to repurchase the outstanding SRC Senior Notes at 101 percent of the principal amount. Upon expiration of the repurchase offer on February 18, 2020, holders of $447.7 million of the outstanding SRC Senior Notes accepted our redemption offer for a total redemption price of approximately $452.2 million, plus accrued and unpaid interest of $6.2 million. We funded the repurchase with proceeds from our revolving credit facility. An aggregate principal amount of approximately $102.3 million of the SRC Senior Notes remains outstanding.

In September 2020, we issued an additional $150.0 million principal amount of our 2026 Senior Notes. The net proceeds from the offering were used to repay a portion of the amount outstanding under our revolving credit facility.

In April 2019, our board of directors approved the Stock Repurchase Program. Effective with the closing of the SRC Acquisition, our board of directors approved an increase and extension to the Stock Repurchase Program from $200 million to $525 million. Pursuant to the Stock Repurchase Program, we repurchased 1.3 million shares and 4.7 million shares of outstanding common stock at a cost of $23.8 million and $154.4 million during the years ended December 31, 2020 and 2019, respectively. We suspended the program in March 2020; however, we reinstated the program in late February 2021, in light of a reduction in our aggregate indebtedness to below $1.5 billion. Repurchases may extend into 2023 based on current market conditions, although the board of directors could elect to suspend or terminate the program at any time, including if certain share price parameters are not achieved. Approximately $346.8 million remained available for repurchases when we reinstated the program.

In addition, we may from time to time seek to pay down, retire or repurchase our outstanding debt using cash or through exchanges of other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on available funds, prevailing market conditions, our liquidity requirements, contractual restrictions in our revolving credit agreement and other factors.

Based on our expected cash flows from operations, our cash and cash equivalents and availability under our revolving credit facility, we believe that we will have sufficient capital available to repay our 2021 Convertible Notes maturing in September 2021 and to fund our planned activities through the 12-month period following the filing of this report.

Our revolving credit facility is available for working capital requirements, capital investments, acquisitions, to support letters of credit and for general corporate purposes. The borrowing base is primarily based on the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests.

The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests on a quarterly basis. The financial tests, as defined per the revolving credit facility, include requirements to: (a) maintain a minimum current ratio of 1.0:1.0 and (b) not exceed a maximum leverage ratio of 4.0:1.0. For purposes of the current ratio covenant, the revolving credit facility's definition of total current assets, in addition to current assets as presented under U.S. GAAP, includes, among other things, unused commitments under the revolving credit facility. Additionally, the current ratio covenant calculation allows us to exclude the current portion of our long-term debt and other short-term loans from the U.S. GAAP total current liabilities amount. Accordingly, the existence of a working capital deficit under U.S. GAAP is not necessarily indicative of a violation of the current ratio covenant. At December 31, 2020, we were in compliance with all covenants in the revolving credit facility with a current ratio of 3.5:1.0 and a leverage ratio of 1.7:1.0. We expect to remain in compliance throughout the 12-month period following the filing of this report.

Cash Flows

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our commodity derivative positions, operating costs and general and administrative expenses. Cash flows from operating activities increased by $11.9 million to $870.1 million in 2020 as compared to $858.2 million in 2019. The increase between periods was primarily due to an increase in commodity derivative settlements and $82.0 million received in June 2020 from the divestiture of certain midstream assets in 2019. The increases were partially offset by a decrease in crude oil, natural gas and NGLs sales and a $84.3 million net decrease in working capital.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $96.2 million in 2020 to $921.6 million from $825.4 million in 2019. The increase was primarily due to the factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and receipts of assets and liabilities. Adjusted free cash flow, a non-U.S GAAP financial measure, increased by $361.6 million in 2020 to $399.3 million from $37.7 million in 2019. The increase was primarily due to a decrease in capital investments in crude oil and natural gas properties.

See *Reconciliation of Non-U.S. GAAP Financial Measures,* below, for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

Investing Activities. As crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our crude oil and natural reserves. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital investments.

Cash flows from investing activities primarily consist of the acquisition, exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. Net cash used in investing activities of $687.2 million during 2020 was primarily related to our drilling and completion activities of $551.0 million and $139.8 million related to the closing of the SRC Acquisition.

Net cash used in investing activities of $677.8 million during 2019 was primarily related to our drilling and completion activities of $855.9 million. Partially offsetting these investing activities was $202.1 million of net cash received from divestitures of certain midstream assets and Delaware Basin crude oil and natural gas properties.

Financing Activities. Net cash used in financing activities in 2020 of $181.3 million was primarily due to the redemption of a portion of the 2025 Senior Notes totaling $452.2 million, the repurchase and retirement of shares of our common stock totaling $23.8 million pursuant to the Stock Repurchase Program and $9.3 million related to purchases of our stock for employee stock-based compensation tax withholding obligations. These financing cash outflows were financed by our net borrowings from our credit facility of $164 million, proceeds from the issuance of 2026 Senior Notes of $148.5 million and cash flows from operating activities.

Net cash used in financing activities in 2019 of $188.9 million was primarily due to the repurchase and retirement of shares of our common stock totaling $154.4 million pursuant to the Stock Repurchase Program, net borrowings from our credit facility of $28.5 million and $4.0 million related to purchases of our stock for employee stock-based compensation tax withholding obligations.

Subsidiary Guarantor

PDC Permian, Inc., a Delaware corporation (the "Guarantor"), our wholly-owned subsidiary, guarantees our obligations under our 2024 Senior Notes, 2025 Senior Notes and 2026 Senior Notes (collectively, the "Senior Notes") and our 2021 Convertible Notes. The Guarantor holds our assets located in the Delaware Basin. The Senior Notes and 2021 Convertible Notes are fully and unconditionally guaranteed on a joint and several basis by the Guarantor. The guarantees are subject to release in limited circumstances only upon the occurrence of certain customary conditions.

The indentures governing the Senior Notes contain customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt including under our revolving credit facility, (b) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict the payment of dividends or other payments by restricted subsidiaries to us, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company.

The following summarized subsidiary guarantor financial information has been prepared on the same basis of accounting as our condensed consolidated financial statements. Investments in subsidiaries are accounted for under the equity method.

	As of/Year Ended December 31,			
	2020		2019	
	Issuer	Guarantor	Issuer	Guarantor
	(in millions)			
Assets				
Current assets	$ 271.4	$ (57.8)	$ 175.8	$ 126.0
Intercompany accounts receivable, guarantor subsidiary	107.3	—	348.8	—
Intercompany accounts receivable, non-guarantor subsidiary	—	—	6.3	—
Investment in guarantor subsidiary	1,767.2	—	1,766.8	—
Properties and equipment, net	3,982.1	877.1	2,328.3	1,766.9
Other non-current assets	56.6	4.3	41.8	6.8
Liabilities				
Current liabilities	$ 751.3	$ 28.5	$ 306.6	$ 52.4
Intercompany accounts payable	—	94.2	—	348.8
Long-term debt	1,409.5	—	1,177.2	—
Other non-current liabilities	254.9	178.1	361.1	211.6
Statement of Operations				
Crude oil, natural gas and NGLs sales	$ 968.8	$ 183.7	$ 999.3	$ 308.0
Commodity price risk management gain (loss), net	180.3	—	(162.8)	—
Total revenues	1,151.5	182.5	838.1	308.7
Production costs	227.0	71.6	180.1	89.2
Gross profit	741.8	112.1	819.2	218.8
Impairment of properties and equipment	2.0	880.4	0.3	38.2
Net income (loss)	(49.2)	(670.0)	(24.6)	(30.0)

Contractual Obligations and Contingent Commitments

The following table presents our contractual obligations and contingent commitments as of December 31, 2020:

	Payments due by period				
Contractual Obligations and Contingent Commitments	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**Thereafter**
			(in millions)		
Long-term liabilities reflected on the consolidated balance sheet					
Long-term debt [1]	$ 1,620.3	$ 200.0	$ 168.0	$ 502.3	$ 750.0
Commodity derivative contracts [2]	134.6	98.2	36.4	—	—
Production tax liability	190.1	124.5	65.6	—	—
Deferred oil gathering credit	18.1	2.2	4.5	4.5	6.9
Deferred midstream gathering credits	168.7	9.4	18.9	18.8	121.6
Asset retirement obligations	166.6	33.9	37.5	37.5	57.7
Operating and finance leases	20.1	8.6	8.7	2.1	0.7
Other liabilities [3]	1.2	0.1	0.2	0.2	0.7
	2,319.7	476.9	339.8	565.4	937.6
Commitments, contingencies and other arrangements [4]					
Interest on long-term debt [5]	420.3	88.5	165.2	123.5	43.1
Firm transportation and processing agreements [6]	516.8	135.4	209.6	124.3	47.5
	937.1	223.9	374.8	247.8	90.6
Total	$ 3,256.8	$ 700.8	$ 714.6	$ 813.2	$ 1,028.2

(1) *Amount presented does not agree with the consolidated balance sheets as it excludes $6.8 million of unamortized net debt discounts and premium and $10.9 million of unamortized debt issuance costs.*

(2) *Represents our gross liability related to the fair value of commodity derivative positions.*

(3) *Includes deferred compensation to former executive officers and deferred payments related to firm transportation agreements.*

(4) *Excludes termination benefits related to employment agreements with our executive officers, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.*

(5) *Amounts presented include $258.8 million to the holders of our 2026 Senior Notes, $98.0 million to the holders of our 2024 Senior Notes, $32.0 million to holders of our 2025 Senior Notes and $2.2 million payable to the holders of our 2021 Convertible Notes. Amounts also include $29.3 million commitment fees due which, as of December 31, 2020, includes a commitment equal to 0.375 percent per annum of the unused portion of the borrowing base of the Company's revolving credit facility. At December 31, 2020, we had variable-rate debt outstanding under our credit facility of $168.0 million.*

(6) *Represents our gross commitment which includes volumes produced by us and purchased from third parties and produced by other third-party working, royalty and overriding royalty interest owners whose volumes we market on their behalf.*

From time to time, we are a party to various legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse effect on our business, financial condition, results of operations or liquidity. Information regarding our legal proceedings can be found in *Note 12 - Commitments and Contingencies - Litigation and Legal Items* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report.

Off-Balance Sheet Arrangements

At December 31, 2020, we had no off-balance sheet arrangements, as defined under SEC rules, which have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital investments or capital resources.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these statements requires us to make certain assumptions, judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities and commitments as of the date of our financial statements. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Our significant accounting policies are described in *Note 2 - Summary of Significant Accounting Policies* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report. We have identified the following policies as critical to the understanding of our financial position and results of operations and which require the application of significant judgment by management.

Crude Oil and Natural Gas Properties. We account for our crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depleted by the unit-of-production method based on estimated proved developed producing reserves. In determining the estimates of reserve and economic evaluations, management utilizes independent petroleum engineers.

Further, under the successful efforts method, exploration costs, including geological and geophysical expenses, seismic costs on unproved leaseholds and delay rentals are expensed as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized, but charged to expense if the well is determined to be economically nonproductive. This accounting method may yield significantly different results than the full cost method of accounting. Judgment is required to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of costs incurred.

The successful efforts method inherently relies on the estimation of proved crude oil, natural gas and NGL reserves. Reserve quantities and the related estimates of future net cash flows are used as inputs in our calculation of depletion, evaluation of proved properties for impairment, assessment of expected realizability of our deferred income tax assets and calculation of the standardized measure of discounted future net cash flows. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. Significant inputs and engineering assumptions used in developing the estimates of proved crude oil and natural gas reserves include reserves volumes, future operating and development costs and historical commodity prices. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. We cannot predict the amounts or timing of such future revisions.

Our reserves estimate has been prepared by our internal and external engineers. For more information regarding reserve estimation, including historical reserve revisions, see *Items 1 and 2. Business and Properties - Preparation of Reserves Estimates* and *Supplemental Oil and Gas Information* to the consolidated financial statements included in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report.

Annually, or upon a triggering event, we assess the valuation of our proved crude oil and natural gas properties for possible impairment by comparing the carrying value to estimated undiscounted future net cash flows on a field-by-field basis using estimated production and prices at which we estimate the commodity will be sold. If carrying values exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a discounted future cash flows analysis. The impairment recorded is the amount by which the carrying values exceed the fair value. In the impairment assessment we estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate.

Future commodity prices are estimated by using a combination of assumptions management uses in its budgeting and forecasting process, historical and future prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. In the event that there are downward revisions in estimates to our estimated reserves quantities, commodity prices significantly decline or rising operating costs, management would test the recoverability of the carrying value of our oil and gas properties and, if necessary, record an impairment charge. Fair value is calculated by discounting the future cash flows. The discount factor used is the market based weighted average cost of capital which is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas.

Although our cash flow estimates are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by their nature, highly uncertain and may vary significantly from actual results.

Unproved properties consist of costs to acquire undeveloped leases as well as costs to acquire unproved reserves. Unproved properties with individually significant acquisition costs are periodically assessed for impairment based on remaining average lease terms, drilling results, reservoir performance, seismic interpretation or changes in future plans to develop acreage. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

Impairment charges would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment charge is recorded.

Asset Retirement Obligations. The majority of our asset retirement obligations ("ARO") relate to the plugging and abandonment of crude oil and gas wells. We account for asset retirement obligations by recording the fair value of our plugging and abandonment obligations when incurred, which is at the time the related well is completed. The recognition of an asset retirement obligation requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate. Over time, the liability is accreted for the change in the present value (accretion expense). The initial capitalized cost, net of salvage value, is depleted over the useful life of the related asset through a charge to DD&A expense. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. When the judgments used to estimate the initial fair value of the asset retirement obligation change, an adjustment is recorded to both the obligation and the carrying amount of the related long-lived asset.

Valuation of Commodity Derivative Financial Instruments. Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas we enter into commodity derivative contracts to protect against price declines in future periods. We have not elected to designate any of our derivative instruments as cash flow hedges; therefore, these instruments do not qualify for hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the consolidated statements of operations. Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the consolidated balance sheet. We measure the fair value of our commodity derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors and nonperformance risk.

Our financial condition, results of operations and liquidity can be significantly impacted by changes in the market value of our commodity derivative instruments due to volatility of commodity prices, including basis differentials.

Deferred Income Tax Asset Valuation Allowance. Deferred income tax assets are recognized for deductible temporary differences, net operating loss carryforwards and credit carryforwards if it is more likely than not that the tax benefits will be realized. We must periodically evaluate whether it is more likely than not we will realize these deferred income tax assets and establish a valuation allowance for those that do not meet the more likely than not threshold. When assessing the need for a valuation allowance, we primarily consider future reversals of existing taxable temporary differences. To a lesser extent, we may also consider future taxable income exclusive of reversing temporary differences and carryfowards, and tax planning strategies that would, if necessary, be implemented to accelerate taxable amounts to utilize expiring carryforwards. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by future operational performance, potential changes in jurisdictional income tax laws and other circumstances surrounding the actual realization of related tax assets.

Valuation of Business Combinations. As part of our business strategy, we regularly pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. As the allocation of the purchase price is subject to significant estimates, the accuracy of this assessment is inherently uncertain.

In estimating the fair values of assets acquired and liabilities assumed the most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties as part of acquisition accounting, we estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. Additionally, for acquisitions with significant unproved properties, we may also review comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value as such sales represent the amount at which a willing buyer and seller would enter into an exchange for such properties to determine an estimation of fair value.

If applicable, we record deferred taxes for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value.

Acreage Exchanges. From time to time, we enter into acreage exchanges in order to consolidate our core acreage positions, enabling us to have more control over the timing of development activities, achieve higher working interests and providing us the ability to drill longer lateral length wells within those core areas. We account for our nonmonetary acreage exchanges of non-producing interests and unproved mineral leases in accordance with the guidance prescribed by Accounting Standards Codification 845, *Nonmonetary Transactions*. For those exchanges that lack commercial substance, we record the acreage received at the net carrying value of the acreage surrendered to obtain it. For those acreage exchanges that are deemed to have commercial substance, we record the acreage received at fair value, with a related gain or loss recognized in earnings, in accordance with Accounting Standards Codification 820, *Fair Value Measurement*. We estimate the fair value of proved crude oil and natural gas properties utilizing the same valuation techniques, significant inputs and assumptions as previously described.

Recent Accounting Pronouncements

See *Note 2 - Summary of Significant Accounting Policies - Recently Adopted Accounting Standards* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report.

Reconciliation of Non-U.S. GAAP Financial Measures

We use "adjusted cash flows from operations," "adjusted free cash flow (deficit)," "adjusted net income (loss)" and "adjusted EBITDAX," non-U.S. GAAP financial measures, for internal management reporting, when evaluating period-to-period changes and, in some cases, in providing public guidance on possible future results. In addition, we believe these are measures of our fundamental business and can be useful to us, investors, lenders and other parties in the evaluation of our performance relative to our peers and in assessing acquisition opportunities and capital expenditure projects. These supplemental measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss) or cash flows from operations, investing or financing activities and should not be viewed as liquidity measures or indicators of cash flows reported in accordance with U.S. GAAP. The non-U.S. GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. In the future, we may disclose different non-U.S. GAAP financial measures in order to help us and our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure.

Adjusted cash flows from operations and adjusted free cash flow (deficit). We believe adjusted cash flows from operations can provide additional transparency into the drivers of trends in our operating cash flows, such as production, realized sales prices and operating costs, as it disregards the timing of settlement of operating assets and liabilities. We believe adjusted free cash flow (deficit) provides additional information that may be useful in an investor analysis of our ability to generate cash from operating activities from our existing oil and gas asset base to fund exploration and development activities and to return capital to stockholders in the period in which the related transactions occurred. We exclude from this measure cash receipts and expenditures related to acquisitions and divestitures of oil and gas properties and capital expenditures for other properties and equipment, which are not reflective of the cash generated or used by ongoing activities on our existing producing properties and, in the case of acquisitions and divestitures, may be evaluated separately in terms of their impact on our performance and liquidity. Adjusted free cash flow is a supplemental measure of liquidity and should not be viewed as a substitute for cash flows from operations because it excludes certain required cash expenditures. For example, we may have mandatory debt service requirements or other non-discretionary expenditures which are not deducted from the adjusted free cash flow measure.

We are unable to present a reconciliation of forward-looking adjusted cash flow because components of the calculation, including fluctuations in working capital accounts, are inherently unpredictable. Moreover, estimating the most directly comparable GAAP measure with the required precision necessary to provide a meaningful reconciliation is extremely difficult and could not be accomplished without unreasonable effort. We believe that forward-looking estimates of adjusted cash flow are important to investors because they assist in the analysis of our ability to generate cash from our operations.

Adjusted net income (loss). We believe that adjusted net income (loss) provides additional transparency into operating trends, such as production, realized sales prices, operating costs and net settlements on commodity derivative contracts, because it disregards changes in our net income (loss) from mark-to-market adjustments resulting from net changes in the fair value of our unsettled commodity derivative contracts, and these changes are not directly reflective of our operating performance.

Adjusted EBITDAX. We believe that adjusted EBITDAX provides additional transparency into operating trends because it reflects the financial performance of our assets without regard to financing methods, capital structure, accounting methods or historical cost basis. In addition, because adjusted EBITDAX excludes certain non-cash expenses, we believe it is not a measure of income, but rather a measure of our liquidity and ability to generate sufficient cash for exploration, development, and acquisitions and to service our debt obligations.

Beginning in the third quarter of 2019, we included a reconciling item for gains or losses on the sale of properties and equipment when calculating adjusted EBITDAX, thereby no longer including such gains or losses in our reported adjusted EBITDAX. We believe this methodology for calculating adjusted EBITDAX will enable greater comparability to our peers, as well as consistent treatment of adjustments for impairment and gains or losses on the sale of properties and equipment. For comparability, all prior periods presented have been conformed to the aforementioned methodology.

PV-10. We define PV-10 as the estimated present value of the future net cash flows from our proved reserves before income taxes, discounted using a 10 percent discount rate. We believe that PV-10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV-10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts, investors and other users of our financial statements may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating us and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves.

The following table presents a reconciliation of each of our non-U.S. GAAP financial measures to its most comparable U.S. GAAP measure:

	Year Ended December 31,		
	2020	2019	2018
		(thousands)	
Cash flows from operations to adjusted cash flows from operations and adjusted free cash flow (deficit):			
Net cash from operating activities	$ 870.1	$ 858.2	$ 889.3
Changes in assets and liabilities	51.5	(32.8)	(80.9)
Adjusted cash flows from operations	921.6	825.4	808.4
Capital expenditures for development of crude oil and natural gas properties	(551.0)	(855.9)	(946.4)
Change in accounts payable related to capital expenditures for oil and gas development activities	28.7	68.2	(36.3)
Adjusted free cash flow (deficit)	$ 399.3	$ 37.7	$ (174.3)
Net income (loss) to adjusted net income (loss):			
Net income (loss)	$ (724.3)	$ (56.7)	$ 2.0
Loss (gain) on commodity derivative instruments	(180.3)	162.8	(145.2)
Net settlements on commodity derivative instruments	279.3	(17.6)	(115.5)
Tax effect of above adjustments (1)	—	(35.2)	62.4
Adjusted net income (loss)	$ (625.3)	$ 53.3	$ (196.3)
Net income (loss) to adjusted EBITDAX:			
Net income (loss)	$ (724.3)	$ (56.7)	$ 2.0
Loss (gain) on commodity derivative instruments	(180.3)	162.8	(145.2)
Net settlements on commodity derivative instruments	279.3	(17.6)	(115.5)
Non-cash stock-based compensation	22.2	23.8	21.8
Interest expense, net	88.7	71.1	70.3
Income tax expense (benefit)	(7.9)	(3.3)	5.4
Impairment of properties and equipment	882.4	38.5	458.4
Exploration, geologic and geophysical expense	1.4	4.1	6.2
Depreciation, depletion and amortization	619.7	644.2	559.8
Accretion of asset retirement obligations	10.1	6.1	5.1
Loss (gain) on sale of properties and equipment	(0.7)	9.7	0.4
Adjusted EBITDAX	$ 990.6	$ 882.7	$ 868.7
Cash from operating activities to adjusted EBITDAX:			
Net cash from operating activities	$ 870.1	$ 858.2	$ 889.3
Interest expense, net	88.7	71.1	70.3
Amortization and write-off of debt discount, premium and issuance costs	(16.8)	(13.6)	(12.8)
Exploration, geologic and geophysical expense	1.4	4.1	6.2
Other	(4.3)	(4.3)	(3.4)
Changes in assets and liabilities	51.5	(32.8)	(80.9)
Adjusted EBITDAX	$ 990.6	$ 882.7	$ 868.7
PV-10:			
Standardized measure of discounted future net cash flows	$ 3,282.2	$ 3,310.3	$ 4,447.7
Present value of estimated future income tax discounted at 10%	172.4	526.7	873.6
PV-10	$ 3,454.6	$ 3,837.0	$ 5,321.3

(1) Due to the full valuation allowance recorded against our net deferred tax assets, there is no tax effect for the year ended December 31, 2020.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rate risks, commodity price risk and credit risk. We have established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our interest bearing cash, cash equivalents and restricted cash accounts and the interest we pay on borrowings under our revolving credit facility. Our 2021 Convertible Notes, 2024 Senior Notes, 2025 Senior Notes and 2026 Senior Notes have fixed rates, and therefore, near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of December 31, 2020, we had $168.0 million outstanding on our revolving credit facility with a weighted average interest rate of 2.4%. If market interest rates would have increased or decreased by one percent, our interest expense for the year ended December 31, 2020 would have changed by approximately $0.4 million.

Commodity Price Risk

We are exposed to the potential risk of loss from adverse changes in the market price of crude oil, natural gas, natural gas basis and NGLs. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. These instruments help us predict with greater certainty the effective crude oil and natural gas prices we will receive for our hedged production. We believe that our commodity derivative policies and procedures are effective in achieving our risk management objectives.

Based on a sensitivity analysis as of December 31, 2020, we estimate that a 10 percent increase in natural gas, crude oil prices and the propane portion of NGLs prices, inclusive of basis, over the entire period for which we have commodity derivatives in place would have resulted in a decrease in the fair value of our net derivative assets of $83.2 million, whereas a 10 percent decrease in prices would have resulted in an increase in fair value of our net derivatives assets of $80.9 million. The potential decrease in the fair value of our net derivative assets would be recorded in statements of operations as a loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure. When exposed to significant credit risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We monitor the creditworthiness of significant counterparties through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. While we believe that our credit risk analysis and monitoring procedures are reasonable, no amount of analysis can assure performance by our counterparties.

We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. Disruption in the credit markets, changes in commodity prices and other factors may have a significant adverse impact on a number of financial institutions. To date, we have had no material counterparty default losses from our commodity derivative financial instruments.

Our crude oil, natural gas and NGLs sales are concentrated with a few predominately large customers. This concentrates our credit risk exposure with a small number of large customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2020, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements, Financial Statement Schedule and Supplemental Information

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of PDC Energy, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of PDC Energy, Inc. and its subsidiaries (the "Company") as of December 31, 2020 and 2019, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2020, including the related notes and financial statement schedule listed in the accompanying index (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above 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. Also 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 *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 10 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

The Impact of Proved Oil and Natural Gas Reserves on Proved Crude Oil and Natural Gas Properties, Net

As described in Notes 2 and 7 to the consolidated financial statements, the Company's proved crude oil and natural gas properties balance was $7,524 million as of December 31, 2020, and depreciation, depletion, and amortization (DD&A) expense for the period ended December 31, 2020 was $619.7 million. As disclosed by management, the process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. Significant inputs and engineering assumptions used in developing the estimates of proved crude oil and natural gas reserves include reserves volumes, future operating and development costs and historical commodity prices. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. The Company accounts for crude oil and natural gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depleted by the unit-of-production method based on estimated proved developed producing reserves. Reserve estimates are prepared by internal and external engineers (collectively "specialists").

The principal considerations for our determination that performing procedures relating to the impact of proved crude oil and natural gas reserves on proved crude oil and gas properties, net is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved crude oil and natural gas reserves, which in turn led to (ii) a high degree of auditor judgement, subjectivity, and effort in performing procedures and evaluating the audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved crude oil and natural gas reserves related to reserves volumes and the assumptions applied to the data related to future operating and development costs, and commodity prices.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved crude oil and natural gas reserves. The work of specialists was used in performing the procedures to evaluate the reasonableness of the reserve volumes. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists' results. These procedures also included, among others, testing the completeness and accuracy of data related to reserves volumes, future operating and development costs, and commodity prices. Additionally, these procedures included evaluating whether the assumptions applied to the aforementioned data were reasonable considering the past performance of the Company.

Valuation of Proved Crude Oil and Natural Gas Properties

As described in Notes 2, 3, and 7 to the consolidated financial statements, as of December 31, 2020, the Company's proved crude oil and natural gas properties were approximately $7,524 million, which includes impairment charges of $753.0 million to write-down proved properties to their estimated fair value and $1,614 million related to a merger completed during the year. Annually, or upon a triggering event, the Company assesses the valuation of its proved crude oil and natural gas properties for possible impairment by comparing the carrying value to estimated undiscounted future net cash flows on a field-by-field basis using estimated production and prices at which the Company estimates the commodity will be sold. If carrying values exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a discounted future cash flows analysis. The impairment recorded is the amount by which the carrying values exceed the fair value. In the impairment assessment and as part of acquisition accounting, management estimates the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate.

The principal considerations for our determination that performing procedures relating to the valuation of proved crude oil and natural gas properties is a critical audit matter are (i) the significant judgment by management when developing the undiscounted future cash flow analysis for the impairment assessment and discounted future cash flow analysis for the impairment assessment and acquisition accounting, (ii) the high degree of auditor judgment, effort, and subjectivity in performing procedures and evaluating management's assumptions related to estimates of reserves volumes, future operating and development costs, future commodity prices and the weighted average cost of capital rate, and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the impairment assessment and development of future cash flows for impairment and the valuation of acquired proved crude oil and natural gas properties. These procedures also included, among others, (i) testing management's process for developing the fair value estimate; (ii) evaluating the appropriateness of the undiscounted and discounted cash flow models, (iii) testing the completeness and accuracy of the underlying data used in the models; and (iv) evaluating the significant assumptions used by management related to reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. Evaluating the reasonableness of management's assumptions related to: (i) future operating and development costs involved consideration of the past and anticipated performance of the Company; and (ii) future commodity prices involved consideration of observable market data. The work of specialists was used in performing the procedures to evaluate the reasonableness of the reserve volumes as stated in the Critical Audit Matter titled "Impact of Proved Oil and Natural Gas Reserves on Proved Crude Oil and Natural Gas Properties, Net". As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists' findings. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the models and the reasonableness of the market based weighted average cost of capital rate.

/s/PricewaterhouseCoopers LLP

Denver, Colorado
February 24, 2021

We have served as the Company's auditor since 2007.

PDC ENERGY, INC.
Consolidated Balance Sheets
(in thousands, except share and per share data)

	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 2,623	$ 963
Accounts receivable, net	244,251	266,354
Fair value of derivatives	48,869	28,078
Prepaid expenses and other current assets	12,505	8,635
Total current assets	308,248	304,030
Properties and equipment, net	4,859,199	4,095,202
Fair value of derivatives	9,565	3,746
Other assets	60,961	45,702
Total Assets	$ 5,237,973	$ 4,448,680
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 90,635	$ 98,934
Production tax liability	124,475	76,236
Fair value of derivatives	98,152	2,921
Funds held for distribution	177,132	98,393
Accrued interest payable	14,734	14,284
Other accrued expenses	81,715	70,462
Current portion of long-term debt	193,014	—
Total current liabilities	779,857	361,230
Long-term debt	1,409,548	1,177,226
Deferred income taxes	—	195,841
Asset retirement obligations	132,637	95,051
Fair value of derivatives	36,359	692
Other liabilities	264,034	283,133
Total liabilities	2,622,435	2,113,173
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 99,758,720 and 61,652,412 issued as of December 31, 2020 and 2019, respectively	998	617
Additional paid-in capital	3,387,754	2,384,309
Accumulated deficit	(772,265)	(47,945)
Treasury shares - at cost, 37,510 and 34,922 as of December 31, 2020 and 2019, respectively	(949)	(1,474)
Total stockholders' equity	2,615,538	2,335,507
Total Liabilities and Stockholders' Equity	$ 5,237,973	$ 4,448,680

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Operations
(in thousands, except per share data)

	Year Ended December 31, 2020	2019	2018
Revenues			
Crude oil, natural gas and NGLs sales	$ 1,152,555	$ 1,307,275	$ 1,389,961
Commodity price risk management gain (loss), net	180,270	(162,844)	145,237
Other income	6,401	11,692	13,461
Total revenues	1,339,226	1,156,123	1,548,659
Costs, expenses and other			
Lease operating expenses	161,346	142,248	130,957
Production taxes	59,368	80,754	90,357
Transportation, gathering and processing expenses	77,835	46,353	37,403
Exploration, geologic and geophysical expense	1,376	4,054	6,204
General and administrative expense	161,087	161,753	170,504
Depreciation, depletion and amortization	619,739	644,152	559,793
Accretion of asset retirement obligations	10,072	6,117	5,075
Impairment of properties and equipment	882,393	38,536	458,397
Loss (gain) on sale of properties and equipment	(724)	9,734	394
Other expense	10,272	11,317	11,829
Total costs, expenses and other	1,982,764	1,145,018	1,470,913
Income (loss) from operations	(643,538)	11,105	77,746
Interest expense, net	(88,684)	(71,099)	(70,317)
Income (loss) before income taxes	(732,222)	(59,994)	7,429
Income tax benefit (expense)	7,902	3,322	(5,406)
Net income (loss)	$ (724,320)	$ (56,672)	$ 2,023
Earnings (loss) per share:			
Basic	$ (7.37)	$ (0.89)	$ 0.03
Diluted	(7.37)	(0.89)	0.03
Weighted-average common shares outstanding:			
Basic	98,251	64,032	66,059
Diluted	98,251	64,032	66,303

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Cash Flows
(in thousands)

	Year Ended December 31,		
	2020	**2019**	**2018**
Cash flows from operating activities:			
Net income (loss)	$ (724,320)	$ (56,672)	$ 2,023
Adjustments to net income (loss) to reconcile to net cash from operating activities:			
Net change in fair value of unsettled commodity derivatives	99,001	145,246	(260,775)
Depreciation, depletion and amortization	619,739	644,152	559,793
Impairment of properties and equipment	882,393	38,536	458,397
Accretion of asset retirement obligations	10,072	6,117	5,075
Non-cash stock-based compensation	22,200	23,837	21,782
Loss (gain) on sale of properties and equipment	(724)	9,734	394
Amortization and write-off of debt discount, premium and issuance costs	16,772	13,575	12,769
Deferred income taxes	(6,530)	(2,256)	6,105
Other	3,004	3,155	2,876
Changes in assets and liabilities:			
Accounts receivable	139,664	(88,304)	12,025
Other assets	(5,341)	(11,560)	(81)
Production tax liability	(50,803)	22,240	35,225
Accounts payable and accrued expenses	(66,183)	(29,578)	16,261
Funds held for future distribution	(23,621)	(7,298)	9,973
Asset retirement obligations	(27,491)	(21,511)	(13,341)
Other liabilities	(17,753)	168,813	20,801
Net cash from operating activities	870,079	858,226	889,302
Cash flows from investing activities:			
Capital expenditures for development of crude oil and natural gas properties	(550,964)	(855,908)	(946,350)
Capital expenditures for other properties and equipment	(1,634)	(20,839)	(11,055)
Acquisition of crude oil and natural gas properties	(139,812)	(13,207)	(180,026)
Proceeds from sale of properties and equipment	1,641	2,105	3,562
Proceeds from divestitures	3,610	202,076	44,693
Restricted cash	—	8,001	1,249
Net cash from investing activities	(687,159)	(677,772)	(1,087,927)
Cash flows from financing activities:			
Proceeds from revolving credit facility and other borrowings	1,799,350	1,577,000	1,072,500
Repayment of revolving credit facility and other borrowings	(1,635,350)	(1,605,500)	(1,040,000)
Proceeds from issuance of senior notes	148,500	—	—
Payment of debt issuance costs	(6,538)	(72)	(7,704)
Purchase of treasury shares	(23,819)	(154,363)	—
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	(9,345)	(4,003)	(5,147)
Redemption of senior notes	(452,153)	—	—
Principal payments under financing lease obligations	(1,905)	(1,952)	(1,495)
Other	—	—	(55)
Net cash from financing activities	(181,260)	(188,890)	18,099
Net change in cash, cash equivalents and restricted cash	1,660	(8,436)	(180,526)
Cash, cash equivalents and restricted cash, beginning of year	963	9,399	189,925
Cash, cash equivalents and restricted cash, end of year	$ 2,623	$ 963	$ 9,399

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Stockholders' Equity
(in thousands, except share data)

	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balance at January 1, 2018	65,955,080	$ 659	$2,503,294	(55,927)	$ (3,008)	$ 6,704	$ 2,507,649
Net income	—	—	—	—	—	2,023	2,023
Stock-based compensation	193,529	2	21,780	—	—	—	21,782
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(102,647)	(5,147)	—	(5,147)
Issuance of treasury shares	—	—	(5,561)	104,068	5,561	—	—
Non-employee directors' deferred compensation plan	—	—	—	9,286	491	—	491
Other	—	—	(90)	—	—	—	(90)
Balance at December 31, 2018	66,148,609	661	2,519,423	(45,220)	(2,103)	8,727	2,526,708
Net loss	—	—	—	—	—	(56,672)	(56,672)
Stock-based compensation	213,745	2	23,835	—	—	—	23,837
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(106,151)	(4,003)	—	(4,003)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(3,803)	—	(127)	3,803	127	—	—
Purchase of treasury shares	—	—	—	(4,706,139)	(154,363)	—	(154,363)
Retirement of treasury shares	(4,706,139)	(46)	(154,317)	4,706,139	154,363	—	—
Issuance of treasury shares	—	—	(4,505)	112,646	4,505	—	—
Balance at December 31, 2019	61,652,412	617	2,384,309	(34,922)	(1,474)	(47,945)	2,335,507
Net loss	—	—	—	—	—	(724,320)	(724,320)
Issuance pursuant to acquisition	39,182,045	391	1,014,921	—	—	—	1,015,312
Stock-based compensation	529,911	5	19,738	—	2,457	—	22,200
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(456,995)	(9,345)	—	(9,345)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(339,648)	(3)	(7,407)	339,648	7,413	—	3
Purchase of treasury shares	—	—	—	(1,266,000)	(23,819)	—	(23,819)
Retirement of treasury shares	(1,266,000)	(12)	(23,807)	1,266,000	23,819	—	—
Issuance of treasury shares	—	—	—	114,759	—	—	—
Balance at December 31, 2020	99,758,720	$ 998	$3,387,754	(37,510)	$ (949)	$ (772,265)	$ 2,615,538

See accompanying Notes to Consolidated Financial Statements

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. is a domestic independent exploration and production company that acquires, explores and develops properties for the production of crude oil, natural gas and NGLs, with operations in the Wattenberg Field in Colorado and the Delaware Basin in west Texas. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays and our Delaware Basin operations are primarily focused in the Wolfcamp zones. We previously operated properties in the Utica Shale in Southeastern Ohio; however, we divested these properties during the first quarter of 2018. As of December 31, 2020, we owned an interest in approximately 3,727 productive gross wells.

The accompanying audited consolidated financial statements include the accounts of PDC and our wholly-owned subsidiaries. Pursuant to the proportionate consolidation method, our accompanying consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated upon consolidation.

During 2020, the effects of coronavirus 2019 (“COVID-19”) led to a significant decline in global demand for crude oil and natural gas, contributing to a drastic reduction in commodity prices and negatively impacting oil and natural gas producers located in the United States, including PDC. The commodity price environment may remain volatile for an extended period as a result of reduced global oil and natural gas demand and the global economic recession. We expect to be able to fund our operations, planned capital expenditures and working capital and other requirements during the next 12 months and the foreseeable future.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates in the Preparation of Financial Statements. The preparation of our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires us to make estimates and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to our consolidated financial statements include estimates of proved oil and natural gas reserves used in calculating depletion; estimates of unpaid revenues and unbilled costs; future cash flows from proved oil and natural gas reserves on proved oil and natural gas properties used in computing impairment test limitations; valuation of commodity derivative instruments; the estimation of future abandonment obligations used in asset retirement obligations; valuation of proved and unproved crude oil and natural gas properties from purchased and exchanged businesses and assets; and valuation of deferred income tax assets.

Cash and Cash Equivalents. The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. Cash and cash equivalents potentially subject us to a concentration of credit risk as substantially all of our deposits held in financial institutions were in excess of federal deposit insurance limits as of December 31, 2020 and 2019. We maintain our cash and cash equivalents in the form of money market and checking accounts with financial institutions that we believe are creditworthy and are also lenders under our revolving credit facility.

Commodity Derivative Financial Instruments. Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas we enter into commodity derivative contracts to protect against price declines in future periods. We have elected not to designate any of our commodity derivative instruments as cash flow hedges; therefore, these instruments do not qualify for hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the consolidated statements of operations. Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the consolidated balance sheet. We measure the fair value of our commodity derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors and nonperformance risk.

Properties and Equipment.

Crude Oil and Natural Gas Properties. We account for our crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depleted by the unit-of-production method based on estimated proved developed producing reserves. We have determined that we have two unit-of-production fields: the Wattenberg Field and the Delaware Basin. In making these conclusions we consider the geographic concentration, operating similarities within the areas, geologic considerations and common cost environments in these areas. We calculate quarterly depletion expense by using our estimated prior period-end reserves as the denominator, with the exception of our fourth quarter where we use the year-end reserve estimate adjusted for fourth quarter production. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. Capitalized development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves. Upon the sale or retirement of significant portions of or complete fields of depreciable or depletable property, the net book value thereof, less proceeds or salvage value, is recognized as a gain or loss.

Exploration costs, including geological and geophysical expenses, seismic costs on unproved leaseholds and delay rentals are expensed as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized, but charged to expense if the well is determined to be economically nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as we have identified a sufficient quantity of reserves to justify completion as a producing well, we are making sufficient progress assessing our reserves and economic and operating viability or we have not made sufficient progress to allow for final determination of productivity. If an in-progress exploratory well is found to be economically unsuccessful prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are charged to exploration expense. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the costs associated with the well are classified as suspended well costs until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time we are able to make a final determination of a well's productive status, the well is removed from suspended well status and the resulting accounting treatment is recorded.

Unproved property costs not subject to depletion primarily include leasehold costs, broker and legal expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Leasehold costs are transferred into costs subject to depletion on an ongoing basis as these properties are evaluated and proved reserves are established. Additional costs not subject to depletion include costs associated with development wells in progress or awaiting completion at year-end. These costs are transferred into costs subject to depletion on an ongoing basis as these wells are completed and proved reserves are established or confirmed.

Proved Property Impairment. Annually, or upon a triggering event, we assess the valuation of our proved crude oil and natural gas properties for possible impairment by comparing the carrying value to estimated undiscounted future net cash flows on a field-by-field basis using estimated production and prices at which we estimate the commodity will be sold. If carrying values exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a discounted future cash flows analysis. The impairment recorded is the amount by which the carrying values exceed the fair value. In the impairment assessment we estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. Certain events, including but not limited to downward revisions in estimates of our reserve quantities, expectations of falling commodity prices or rising operating costs, could result in a triggering event, and may result to a possible impairment of our proved crude oil and natural gas properties.

Unproved Property Impairment. Acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to impairment expense. Unproved crude oil and natural gas properties with individually significant acquisition costs are assessed for impairment periodically, or if a triggering event is identified.

Other Property and Equipment. Other property and equipment such as pipelines, vehicles, facilities, office furniture and equipment, buildings and computer hardware and software is carried at cost. Depreciation is provided principally on the straight-line method over the assets' estimated useful lives, which range from two to 35 years. Total depreciation expense related to other property and equipment was $8.7 million, $5.7 million and $8.5 million for the year ended December 31, 2020, 2019 and 2018, respectively.

We review other property and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying value of the asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying value of the asset exceeds the estimated future cash flows, an impairment charge is recognized for the amount by which the carrying value of the asset exceeds its fair value.

Maintenance and repair costs on other property and equipment are charged to expense as incurred. Major renewals and improvements are capitalized and depreciated over the remaining useful life of the asset. Upon the sale or other disposition of assets, the cost and related accumulated DD&A are removed, the proceeds are applied and any resulting gain or loss is recognized.

Internal-Use Software. Internal-use software costs incurred during the development stage of our enterprise resource planning software are capitalized. The development stage generally includes software design, configuration, testing and installation activities. Training and maintenance costs are expensed as incurred, while upgrades and enhancements are capitalized if it is probable that such expenditures will result in additional functionality. Capitalized internal-use software costs are depreciated over the estimated useful life of the underlying project on a straight-line basis upon completion of the project.

Capitalized Interest. Interest costs are capitalized as part of the historical cost of acquiring assets. Investments in unproved crude oil and natural gas properties and major development projects, on which DD&A expense is not currently recorded and on which exploration or development activities are in progress, qualify for capitalization of interest. Major construction projects also qualify for interest capitalization until the asset is ready to be placed into service. Capitalized interest is calculated by multiplying our weighted-average interest rate on our outstanding debt by the qualifying costs. Interest capitalized may not exceed gross interest expense for the period. As the qualifying asset is placed into service, we begin amortizing the related capitalized interest over the useful life of the asset. Capitalized interest totaled $19.7 million, $13.4 million and $9.2 million during the year ended December 31, 2020, 2019 and 2018, respectively.

Assets Held-for-Sale. Assets held-for-sale are valued at the lower of their carrying amount or estimated fair value, less costs to sell. If the carrying amount of the assets exceeds their estimated fair value, an impairment loss is recognized. Fair values are estimated using accepted valuation techniques, such as a discounted cash flow model, earnings multiples or indicative bids, when available. We consider historical experience and all available information at the time the estimates are made; however, the fair value that is ultimately realized upon the sale of the assets to be divested may differ from the estimated fair values reflected on the consolidated financial statements. DD&A expense is not recorded on assets once they are classified as held-for-sale. Assets classified as held-for-sale are expected to be disposed of within one year.

Income Taxes. We account for income taxes under the asset and liability method. We recognize deferred income tax assets and liabilities for the future tax consequences attributable to operating loss and credit carryforwards and differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred income tax assets and liabilities are measured using enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. If we determine that it is more likely than not that some portion or all of the deferred income tax assets will not be realized, we record a valuation allowance, thereby reducing the deferred income tax assets to what we consider realizable.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The Company's policy is to recognize interest and penalties related to uncertain tax positions in interest expense.

Debt Issuance Costs and Discounts. Debt issuance costs and discounts are capitalized and amortized over the life of the respective borrowings using the effective interest method. Debt issuance costs for the Senior Notes are included in long-term debt and the debt issuance costs for the revolving credit facility are included in other assets.

Asset Retirement Obligations. We recognize the estimated liability for future costs associated with the plugging and abandonment of our oil and gas properties resulting from acquisition, construction or normal operation. We account for asset retirement obligations by recording the fair value of our plugging and abandonment obligations when incurred, which is at the time the related well is completed. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the associated long-lived asset by the same amount as the liability. Over time, the liability is accreted for the change in the present value (accretion expense). The initial capitalized cost, net of salvage value, is depleted over the useful life of the related asset through a charge to DD&A expense. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from, among other things, changes in retirement costs or the estimated timing of settling asset retirement obligations.

Treasury Shares. We record treasury share purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as a reduction in shareholders’ equity. When we retire treasury shares, we charge any excess of cost over the par value to additional paid-in-capital ("APIC"), to the extent we have amounts in APIC, with any remaining excess cost being charged to retained earnings.

Revenue Recognition. Crude oil, natural gas and NGLs revenues are recognized when we have transferred control of crude oil, natural gas or NGLs production to the purchaser. We consider the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from, the crude oil, natural gas or NGLs production. We record revenues based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes delivered and prices received. We receive payment for sales one to two months after actual delivery has occurred. The differences in sales estimates and actual sales are recorded one to two months later. Historically, these differences have not been material. We account for natural gas imbalances using the sales method. For the years ending December 31, 2020, 2019 and 2018, the impact of any natural gas imbalances was not significant.

Our crude oil, natural gas and NGLs sales are recorded using either the “net-back” or "gross" method of accounting, depending upon the related agreement. We use the net-back method when control of the crude oil, natural gas or NGLs has been transferred to the purchasers of these commodities that are providing transportation, gathering or processing services. In these situations, the purchaser pays us proceeds based on a percent of the proceeds or have fixed our sales price at index less specified deductions. The net-back method results in the recognition of a net sales price that is lower than the index for which the production is based because the operating costs and profit of the midstream facilities are embedded in the net price we are paid.

We use the gross method of accounting when control of the crude oil, natural gas or NGLs is not transferred to the purchaser and the purchaser does not provide transportation, gathering or processing services as a function of the price we receive. Rather, we contract separately with midstream providers for the applicable transport and processing on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering and processing expenses.

For our product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606 which states the Company is not required to disclose the transaction price allocated to the remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, monthly sales of a product generally represent a separate performance obligation; therefore, future commodity volumes to be delivered and sold are wholly unsatisfied and disclosure of the transaction price allocated to such unsatisfied performance obligations is not required.

Business Combinations. We utilize the acquisition method to account for acquisitions of businesses. Pursuant to the acquisition method, we allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based upon appraisals, discounted cash flows and estimates by management, which are Level 3 inputs. When appropriate, we review recent comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value; for example, the amount at which a willing buyer and seller would enter into an exchange for such properties.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped and unproved crude oil and natural gas properties. To estimate the fair value of these properties as part of acquisition accounting, we estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. The market based weighted average cost of capital rate is subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by additional risk-weighting factors. Additionally, for acquisitions with significant unproved properties, we complete an analysis of recent comparable purchased properties to determine an estimation of fair value.

If applicable, we record deferred taxes for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Acreage Exchanges. From time to time, we enter into acreage exchanges in order to consolidate our core acreage positions, enabling us to have more control over the timing of development activities, achieve higher working interests and provide us the ability to drill longer lateral length wells within those core areas. We account for our nonmonetary acreage exchanges of non-producing interests and unproved mineral leases in accordance with the guidance prescribed by Accounting Standards Codification 845, *Nonmonetary Transactions*. For those exchanges that lack commercial substance, we record the acreage received at the net carrying value of the acreage surrendered to obtain it. For those acreage exchanges that are deemed to have commercial substance, we record the acreage received at fair value, with a related gain or loss recognized in earnings, in accordance with Accounting Standards Codification 820, *Fair Value Measurement*.

Stock-Based Compensation. Stock-based compensation is recognized within our financial statements based on the grant-date fair value of the equity instrument awarded. Stock-based compensation expense is recognized in the financial statements on a straight-line basis over the requisite service period for the entire award and we account for forfeitures of stock-based compensation awards as they occur.

Fair Value of Assets and Liabilities. The Company follows the authoritative accounting guidance for measuring fair value of assets and liabilities in its financial statements. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

Leases. We determine if an arrangement is representative of a lease at contract inception. Right-of-use ("ROU") assets represent our right to use the underlying assets for the lease term and the corresponding lease liabilities represent our obligations to make lease payments arising from the leases. Operating and finance lease ROU assets and liabilities are recognized at the commencement date based on the present value of the expected lease payments over the lease term. As most of our leases do not provide an implicit interest rate, we utilize our incremental borrowing rate based on information available at the commencement date in determining the present value of lease payments. Subsequent measurement, as well as presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. Terms of our leases include options to extend or terminate the lease only when we can ascertain that it is reasonably certain we will exercise that option. Leases with an initial term of one year or less are not recorded on the consolidated balance sheets.

We apply the practical expedient that permits combining lease and non-lease components in a contract and accounting for the combination as a single lease component (applied by asset class).

Recently Adopted Accounting Pronouncement

In March 2020, the SEC adopted final rules that amend the financial disclosure requirements for subsidiary issuers and guarantors of registered debt securities in Rule 3-10 of Regulation S-X. The amended rules, which can be found under new Rule 13-01 of Regulation S-X, narrow the circumstances that require separate financial statements of subsidiary issuers and guarantors and streamline the alternative disclosures required in lieu of those statements. The amended rules allow registrants, among other things, to disclose summarized financial information of the issuer and guarantors on a combined basis and to present only the most recently completed fiscal year and subsequent year-to-date interim period. The rule replaces the requirement to provide condensed consolidating financial information with a requirement to present summarized financial information of the issuers and guarantors. These disclosures may be included in the notes to the consolidated financial statements or can be disclosed outside the notes to the consolidated financial statements (i.e. management's discussion and analysis section). The rule is effective in the first quarter of 2021, with earlier adoption permitted. We early adopted the rule in the first quarter of 2020 and have provided these disclosures outside the notes to the condensed consolidated financial statements. In October 2020, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2020-09, *Amendments to SEC Paragraphs Pursuant to SEC Release No. 33-10762*, to align the standards under Accounting Standard Codification 470, *Debt*, with the SEC final rules discussed above.

Recently Issued Accounting Pronouncement but Not Yet Adopted

In August 2020, FASB issued Accounting Standards Update ("ASU") No. 2020-06, *Debt - Debt with conversion and other options and derivatives and hedging on contracts in entity's own equity.* Amendments in this ASU simplify accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts on an entity's own equity. The amendments remove the separation models for convertible debt instruments with cash conversion features and convertible instruments with beneficial conversion features. Consequently, a convertible debt instrument will be accounted for as a single liability measured at its amortized cost and convertible preferred stock will be accounted for as a single equity instrument measured at its historical cost as long as no other features require bifurcation and recognition as derivatives. The amendments also modify the accounting for certain contracts in an entity's own equity that are currently accounted for as derivatives because of specific settlement provisions. Lastly, the earnings per share ("EPS") calculation is being amended to (i) require entities to use the if-converted method for all convertible instruments and include the effect of potential share settlement; (ii) clarify that the average market price for the period should be used in the computation of the diluted EPS denominator; and (iii) require entities to use the weighted-average share count from each quarter when calculating the year-to-date weighted average share count for all potentially dilutive securities. The amendments in this ASU are effective for fiscal years beginning after December 31, 2021, including interim periods within those fiscal years and early adoption is permitted. We completed our evaluation of this ASU and we concluded that the amendments would not have a significant impact on our financial statements. We do not intend to adopt the amendments early.

NOTE 3 - BUSINESS COMBINATION

In January 2020, we merged with SRC in a transaction valued at $1.7 billion, inclusive of SRC's net debt (the "SRC Acquisition"). SRC was an independent oil and natural gas company engaged in the exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in Weld County, Colorado. The acquisition added approximately 83,000 net acres which are located on large, contiguous acreage blocks in the core of the Wattenberg Field. Upon closing, we issued approximately 38.9 million shares of our common stock to SRC shareholders and holders of SRC equity awards, reflecting the issuance of 0.158 of a share of our common stock in exchange for each outstanding share of SRC common stock and the cancellation of outstanding SRC equity awards pursuant to the terms of the merger agreement that we entered into with the SRC (the "Merger Agreement"). During the year ended December 31, 2020, we recorded transaction costs related to the SRC Acquisition of $19.9 million. These expenses were accounted for separately from the assets and liabilities assumed and are included in general and administrative expense in the consolidated statements of operations.

The following table details our final purchase price, valuation and allocation of the purchase price to the assets acquired and liabilities assumed as a result of the SRC Acquisition:

		(in thousands)
Consideration:		
Cash	$	40
Retirement of seller's credit facility		166,238
Total cash consideration		166,278
Common stock issued		1,009,015
Shares withheld in lieu of taxes		6,299
Total consideration	$	1,181,592
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Assets acquired:		
Current assets	$	145,792
Properties and equipment, net - proved		1,613,674
Properties and equipment, net - unproved		109,615
Properties and equipment, net - other		16,242
Deferred tax asset		189,311
Other assets		11,810
Total assets acquired	$	2,086,444
Liabilities assumed:		
Current liabilities	$	(253,967)
Senior notes		(555,500)
Asset retirement obligations		(42,417)
Other liabilities		(52,968)
Total liabilities assumed		(904,852)
Total identifiable net assets acquired	$	1,181,592

This acquisition was accounted for under the acquisition method of accounting for business combinations. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved and unproved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, lease terms and expirations and a market-based weighted-average cost of capital rate of 10 percent. These inputs require significant judgments and estimates by management at the time of the valuation.

The results of operations for the SRC Acquisition since the closing date have been included in our consolidated financial statements for the year ended December 31, 2020 and include approximately $320.9 million of total revenue, and $46.5 million of income from operations.

Pro Forma Information. The following unaudited pro forma financial information represents a summary of the consolidated results of operations for the years ended December 31, 2020 and 2019, assuming the acquisition had been completed as of January 1, 2019. The information below reflects certain nonrecurring pro forma adjustments that were directly related to the business combination based on available information and certain assumptions that we believe are reasonable, including (i) the Company's common stock issued to convert SRC's outstanding shares of common stock and equity awards, (ii) the depletion of SRC's fair-valued proved oil and gas properties using the successful efforts method of accounting and (iii) the estimated tax impacts of the proforma adjustments, if any. The pro forma financial information is not necessarily indicative of the results of operations that would have been achieved if the acquisition had been effective as of these dates, or of future results.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company and SRC totaling approximately $38.0 million and $15.9 million for the years ended December 31, 2020 and 2019, respectively.

	Year Ended December 31,	
	2020	**2019**
	(in thousands, except per share data)	
Total revenue	$ 1,361,051	$ 1,761,498
Net income (loss)	(695,663)	139,578
Earnings (loss) per share:		
Basic	$ (6.97)	$ 1.36
Diluted	(6.97)	1.35

NOTE 4 - REVENUE RECOGNITION

Disaggregated Revenue. The following table presents crude oil, natural gas and NGLs sales disaggregated by commodity and operating region for the periods presented:

Revenue by Commodity and Operating Region	Year Ended December 31, 2020	2019	2018
	(in thousands)		
Crude oil			
Wattenberg Field	$ 668,948	$ 767,760	$ 783,158
Delaware Basin	147,902	252,929	252,107
Utica Shale [(1)]	—	—	2,696
Total	816,850	1,020,689	1,037,961
Natural gas			
Wattenberg Field	171,755	137,143	130,073
Delaware Basin	6,997	13,877	32,010
Utica Shale [(1)]	—	—	1,109
Total	178,752	151,020	163,192
NGLs			
Wattenberg Field	128,126	94,347	132,820
Delaware Basin	28,827	41,219	55,148
Utica Shale [(1)]	—	—	840
Total	156,953	135,566	188,808
Revenue by Operating Region			
Wattenberg Field	968,829	999,250	1,046,051
Delaware Basin	183,726	308,025	339,265
Utica Shale [(1)]	—	—	4,645
Total	$ 1,152,555	$ 1,307,275	$ 1,389,961

(1) In March 2018, we completed the disposition of our Utica Shale properties.

Contract Assets. Contract assets include material contributions in aid of construction, which are common in purchase and processing agreements with midstream service providers that are our customers. The intent of the payments is primarily to reimburse the customer for actual costs incurred related to the construction of its gathering and processing infrastructure. Contract assets are included in other assets on the consolidated balance sheets. The contract assets are amortized as a reduction to crude oil, natural gas and NGLs sales revenue during the periods in which the related production is transferred to the customer.

The following table presents the changes in carrying amounts of the contract assets associated with our crude oil, natural gas and NGLs sales revenue for the periods presented:

	December 31, 2020	2019
	(in thousands)	
Beginning balance	$ 11,494	$ 11,144
Additions	16,739	443
Amortized as a reduction to crude oil, natural gas and NGLs sales	(2,361)	(93)
Ending balance	$ 25,872	$ 11,494

NOTE 5 - FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

Derivative Financial Instruments. We measure the fair value of our commodity derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of derivative liabilities and the effect of our counterparties' credit standings on the fair value of derivative assets. Both inputs to the model are based on published credit default exchange rates and the duration of each outstanding derivative position. We validate our fair value measurement by corroborating the original source of inputs, monitoring changes in valuation methods and assumptions, and reviewing counterparty statements and other supporting documentation.

Our crude oil and natural gas fixed-price exchanges are included in Level 2. Our collars are included in Level 3. Our basis exchanges are included in Level 2 and Level 3. The following table presents, for each applicable level within the fair value hierarchy, our derivative assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis as of the periods presented:

	December 31,					
	2020			2019		
	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Total assets	$ 36,895	$ 21,539	$ 58,434	$ 22,886	$ 8,938	$ 31,824
Total liabilities	(104,545)	(29,966)	(134,511)	(3,089)	(524)	(3,613)
Net derivative instruments	$ (67,650)	$ (8,427)	$ (76,077)	$ 19,797	$ 8,414	$ 28,211

The following table presents a reconciliation of our Level 3 assets and liabilities measured at fair value:

	Year Ended December 31,		
	2020	2019	2018
	(in thousands)		
Fair value of Level 3 instruments, net asset (liability) beginning of period	$ 8,414	$ 58,329	$ (9,687)
Changes in fair value included in consolidated statements of operations line item:			
Commodity price risk management gain (loss), net	37,821	(41,749)	63,257
Settlements included in consolidated statements of operations line items:			
Commodity price risk management gain (loss), net	(54,662)	(8,166)	4,759
Fair value of Level 3 instruments, net asset (liability) end of period	$ (8,427)	$ 8,414	$ 58,329
Net change in fair value of Level 3 unsettled derivatives included in consolidated statements of operations line item:			
Commodity price risk management gain (loss), net	$ —	$ (22,694)	$ —
Total	$ —	$ (22,694)	$ —

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve, which is provided by a third-party vendor. A significant increase or decrease in the implied volatility, in isolation, would have a directionally similar effect resulting in a significantly higher or lower fair value measurement of our Level 3 derivative contracts. There has been no change in the methodology we apply to measure the fair value of our Level 3 derivative contracts during the periods covered by the financial statements.

Nonrecurring Fair Value Measurements

Acquisitions and impairment of long-lived assets. We utilize fair value with inputs that are not observable in the market, therefore designated as Level 3 within the valuation hierarchy, on a nonrecurring basis for any acquired assets or businesses and to review our proved and unproved crude oil and natural gas properties for possible impairment.

Asset Retirement Obligations. We measure the fair value of asset retirement obligations as of the date a well begins drilling or when production equipment and facilities are installed using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 within the valuation hierarchy.

Other Financial Instruments

The carrying value of the financial instruments included in current assets and current liabilities approximates fair value due to the short-term maturities of these instruments.

Long-term debt. The portion of our long-term debt related to our revolving credit facility approximates fair value, as the applicable interest rates are variable and reflective of market rates. We have not elected to account for the portion of our debt related to our senior notes under the fair value option; however, we have determined an estimate of the fair values based on measurements of trading activity and broker or dealer quotes, which are published market prices, and therefore are Level 2 inputs. The table below presents these estimates of the fair value of the portion of our long-term debt related to our senior notes and convertible notes as of the dates indicated:

	December 31,			
	2020		2019	
	Estimated Fair Value	Percent of Par	Estimated Fair Value	Percent of Par
	(in millions)			
Senior notes:				
2021 Convertible Notes	$ 196.2	98.1 %	$ 188.6	94.3 %
2024 Senior Notes	410.8	102.7 %	409.2	102.3 %
2025 Senior Notes	102.8	100.5 %	—	— %
2026 Senior Notes	775.5	103.4 %	599.4	99.9 %

NOTE 6 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

Objective and Strategy. Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas we enter into commodity derivative contracts such as collars, fixed-price exchanges and basis protection exchanges, to protect against price declines in future periods. We do not enter into derivative contracts for speculative or trading purposes.

We believe our commodity derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels. As of December 31, 2020, we had derivative instruments in place for a portion of our anticipated 2021 and 2022 production. Our commodity derivative contracts have been entered into at no upfront cost to us as we hedge our anticipated production at the then-prevailing commodity market prices, without adjustment for premium or discount.

As of December 31, 2020 and 2019, our derivative instruments were comprised of fixed-price swaps, collars and basis protection swaps.

- Fixed-price swaps are arrangements that guarantee a fixed price. If the index price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the index price and the fixed contract price from the counterparty. If the index price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the index price and the fixed contract price to the counterparty;

- Collars contain a fixed floor price (put) and ceiling price (call). If the index price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and index price from the counterparty. If the index price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and index price to the counterparty. If the index price is between the put and call strike price, no payments are due to or from the counterparty;

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For basis protection swaps, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

Commodity Derivative Contracts. As of December 31, 2020, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted-average contract price is shown.

	Collars			Fixed-Price Exchanges		
	Quantity *(Crude oil - MBbls Natural Gas - BBtu)*	Weighted-Average Contract Price		Quantity *(Crude Oil - MBbls Gas and Basis-BBtu)*	Weighted-Average Contract Price	Fair Value December 31, 2020 (1) *(in thousands)*
Commodity/ Index/ Maturity Period		**Floors**	**Ceilings**			
Crude Oil						
NYMEX						
2021	4,008	$ 38.76	$ 50.05	10,176	$ 47.01	$ (20,341)
2022	900	40.00	52.05	4,884	41.18	(26,440)
Total Crude Oil	4,908			15,060		(46,781)
Natural Gas						
NYMEX						
2021	62,625	2.46	2.86	31,800	2.40	(9,169)
2022	17,400	2.50	2.89	8,700	2.62	1,325
Total Natural Gas	80,025			40,500		(7,844)
Basis Protection - Natural Gas						
CIG						
2021	—	—	—	94,425	(0.46)	(19,773)
2022	—	—	—	26,100	(0.34)	(1,679)
Total Basis Protection - Natural Gas	—			120,525		(21,452)
Commodity Derivatives Fair Value						$ (76,077)

Effect of Derivative Instruments on the Consolidated Balance Sheet. The following table presents the consolidated balance sheet line item and fair value amounts of our derivative instruments as of the dates indicated:

		Consolidated Balance Sheet Line Item	December 31, 2020	December 31, 2019
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts	Fair value of derivatives	$ 48,869	$ 27,766
	Basis protection derivative contracts	Fair value of derivatives	—	312
			48,869	28,078
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	9,565	3,746
Total derivative assets			$ 58,434	$ 31,824
Derivative liabilities:	Current			
	Commodity derivative contracts	Fair value of derivatives	$ 78,379	$ 529
	Basis protection derivative contracts	Fair value of derivatives	19,773	2,392
			98,152	2,921
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	34,680	692
	Basis protection derivative contracts	Fair value of derivatives	1,679	—
Total derivative liabilities			$ 134,511	$ 3,613

Our financial derivative agreements contain master netting provisions that provide for the net settlement of contracts through a single payment in the event of early termination. We have elected not to offset the fair value positions recorded on our consolidated balance sheets.

The following table reflects the impact of netting agreements on gross derivative assets and liabilities:

As of December 31, 2020	Total Gross Amount Presented on Balance Sheet	Effect of Master Netting Agreements	Total Net Amount
		(in thousands)	
Derivative assets:			
Derivative instruments, at fair value	$ 58,434	$ (39,691)	$ 18,743
Derivative liabilities:			
Derivative instruments, at fair value	$ 134,511	$ (39,691)	$ 94,820

As of December 31, 2019	Total Gross Amount Presented on Balance Sheet	Effect of Master Netting Agreements	Total Net Amount
		(in thousands)	
Derivative assets:			
Derivative instruments, at fair value	$ 31,824	$ (2,619)	$ 29,205
Derivative liabilities:			
Derivative instruments, at fair value	$ 3,613	$ (2,619)	$ 994

Effect of Derivative Instruments on the Consolidated Statements of Operations. The following table presents the impact of our derivative instruments on our consolidated statements of operations:

	Year Ended December 31,		
Consolidated Statements of Operations Line Item	**2020**	**2019**	**2018**
		(in thousands)	
Commodity price risk management gain (loss), net			
Net settlements	$ 279,271	$ (17,598)	$ (115,538)
Net change in fair value of unsettled derivatives	(99,001)	(145,246)	260,775
Total commodity price risk management gain (loss), net	$ 180,270	$ (162,844)	$ 145,237

Derivative Counterparties. Our commodity derivative instruments expose us to credit risk of non-performance by our counterparties. We primarily use financial institutions who are also lenders under our revolving credit facility as counterparties to our commodity derivative contracts. To date, we have had no derivative counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our current counterparties on the fair value of our derivative instruments is not significant at December 31, 2020; however, this determination may change.

NOTE 7 - PROPERTIES AND EQUIPMENT, NET

The following table presents the components of properties and equipment, net of accumulated DD&A, as of the dates indicated:

	December 31,	
	2020	**2019**
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 7,523,639	$ 6,241,780
Unproved	350,677	403,379
Total crude oil and natural gas properties	7,874,316	6,645,159
Infrastructure and other	65,027	41,888
Land and buildings	24,299	12,312
Construction in progress	523,550	408,428
Properties and equipment, at cost	8,487,192	7,107,787
Accumulated DD&A	(3,627,993)	(3,012,585)
Properties and equipment, net	$ 4,859,199	$ 4,095,202

Midstream Asset Divestitures. During the second quarter of 2019, we completed the sales of our Delaware Basin produced water gathering and disposal, crude oil gathering and natural gas gathering assets (the "Midstream Asset Divestitures") for aggregate proceeds of $345.6 million. The proceeds were received upon closing, with the exception of $82.0 million that we received in June 2020. Concurrent with the Midstream Asset Divestitures, we entered into agreements with the purchasers which provide us with certain gathering, processing, transportation and water disposal services. See *Note 8 - Accounts Receivable, Other Accrued Expenses and Other Liabilities* for further details regarding these agreements. Proceeds were allocated first to the assets sold based upon the fair values of the tangible assets sold, with the remainder of $179.6 million allocated to the acreage dedication agreements. We recorded an aggregate gain on the sale of $34.0 million based on the fair value of the tangible assets sold.

The Midstream Asset Divestitures did not represent a strategic shift in our operations or have a significant impact on our operations or financial results; therefore, we did not account for the divested assets as discontinued operations.

Impairments. The following table presents impairment charges recorded for properties and equipment:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Impairment of proved and unproved properties	$ 881,238	$ 10,599	$ 458,397
Impairment of infrastructure and other	1,155	27,937	—
Total impairment of properties and equipment	$ 882,393	$ 38,536	$ 458,397

Oil and Gas Properties.

In the first quarter of 2020, the significant decline in crude oil prices in addition to the ongoing effects of COVID-19 was considered a triggering event that required us to assess our crude oil and natural gas properties for possible impairment. As a result of our assessment, we recorded impairment expense of $881.1 million to our proved and unproved properties.

Proved Properties. Of the total impairment expense recognized, approximately $753.0 million was related to our Delaware Basin proved properties. These impairment charges represented the amount by which the carrying value of the crude oil and natural gas properties exceeded the estimated fair value. We estimated the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount, a level 3 input. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a discount rate of 17 percent, which was based on a weighted-average cost of capital for the area where the assets are located. There were no further triggering events identified for the remainder of 2020.

There were no impairment charges recognized related to our proved properties during the years ended December 31, 2019 and 2018.

Unproved Properties. We recognized approximately $127.3 million of impairment charges for our unproved properties in the Delaware Basin during the three months ended March 31, 2020. These impairment charges were recognized based on the fair value of the properties, a Level 3 input. The fair value is estimated based on a review of our current drilling plans, estimated future cash flows for probable well locations and expected future lease expirations, primarily in areas where we have no development plans. There were no further triggering events identified for the remainder of 2020.

During the years ended December 31, 2019 and 2018, we recorded impairment charges totaling $10.6 million and $458.4 million related to the divestiture of unproved leaseholds and then-current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin that we determined not to develop.

Other Property and Equipment Impairment. During the year ended December 31, 2019, we recorded impairments of $27.9 million related to certain midstream facility infrastructure in the Delaware Basin. Upon closing of the Midstream Asset Divestitures, it was determined that the net book value of these assets was not recoverable.

Suspended Well Costs. The following table presents the capitalized exploratory well cost pending determination of proved reserves and included in properties and equipment as of the dates indicated:

	December 31,	
	2020	2019
	(in thousands, except for number of wells)	
Beginning balance	$ 16,078	$ 12,188
Additions to capitalized exploratory well costs pending the determination of proved reserves	11,770	31,901
Reclassifications to proved properties	(20,389)	(28,011)
Ending balance	$ 7,459	$ 16,078
Number of wells pending determination at period-end	2	4

Our net capitalized exploratory well costs that have been capitalized for a period greater than one year as of December 31, 2020 was $7.5 million, which consists of the entire balance of our suspended well costs. We expect to complete our two gross suspended wells associated with two projects in the first half of 2021. We did not have any capitalized costs for a period greater than one year as of December 31, 2019. During 2020, two wells classified as exploratory as of December 31, 2019 were reclassified as productive and no new wells drilled were classified as exploratory.

Exploration Expenses. The following table presents the major components of exploration, geologic and geophysical expense:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Geological and geophysical costs, including seismic purchases	$ 253	$ 3,017	$ 3,401
Exploratory dry hole costs	—	—	113
Operating, personnel and other	1,123	1,037	2,690
Total exploration, geologic and geophysical expense	$ 1,376	$ 4,054	$ 6,204

NOTE 8 - ACCOUNTS RECEIVABLE, OTHER ACCRUED EXPENSES AND OTHER LIABILITIES

Accounts Receivable. The following table presents the components of accounts receivable, net of allowance for doubtful accounts as of the dates indicated:

	December 31,	
	2020	2019
	(in thousands)	
Crude oil, natural gas and NGLs sales	$ 178,147	$ 149,758
Joint interest billings	50,329	29,510
Midstream asset divestitures deferred payments	—	81,702
Other	22,538	12,860
Allowance for doubtful accounts	(6,763)	(7,476)
Accounts receivable, net	$ 244,251	$ 266,354

The Company's accounts receivable consists mainly of receivables from (i) crude oil, natural gas and NGLs purchasers, (ii) receivable from joint interest owners in the properties we operate and (iii) from derivative counterparties. Most payments for production are received within two months after the production date. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

Credit and Concentration Risk. Inherent to our industry is the concentration of crude oil, natural gas and NGLs sales to a limited number of customers. This concentration has the potential to impact our overall exposure to credit risk in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. As of December 31, 2020 and 2019, four of our customers represented 10 percent or more of our crude oil, natural gas and NGLs accounts receivable balance.

During the year ended December 31, 2020, four customers accounted for approximately 31 percent, 17 percent, 16 percent and 13 percent of our total crude oil, natural gas and NGLs sales. During the year ended December 31, 2019, four customers accounted for approximately 20 percent, 17 percent,16 percent and 11 percent of our total crude oil, natural gas and NGLs sales. During the year ended December 31, 2018, one customer accounted for approximately 13 percent of our total crude oil, natural gas and NGLs sales. However, given the liquidity in the market for the sale of hydrocarbons, we believe that the loss of any single purchaser, or the aggregate loss of several purchasers, could be managed by selling to alternative purchasers.

Other Accrued Expenses. The following table presents the components of other accrued expenses as of the dates indicated:

	December 31,	
	2020	2019
	(in thousands)	
Employee benefits	$ 23,304	$ 21,611
Asset retirement obligations	33,933	32,200
Environmental expenses	10,139	2,256
Operating and finance leases	7,986	5,926
Other	6,353	8,469
Other accrued expenses	$ 81,715	$ 70,462

Other Liabilities. The following table presents the components of other liabilities as of the dates indicated:

	December 31,	
	2020	2019
	(in thousands)	
Deferred midstream gathering credits	$ 168,478	$ 175,897
Deferred oil gathering credits	18,090	20,100
Production taxes	65,592	68,020
Operating and finance leases	10,763	15,779
Other	1,111	3,337
Other liabilities	$ 264,034	$ 283,133

Deferred Midstream Gathering Credits. In the second quarter of 2019, concurrent with the sale of our Delaware Basin midstream assets, we entered into an agreement with the purchasers that dedicated the gathering of certain of our production and all water gathering and disposal volumes in the Delaware Basin. The terms of these agreements range from 15 to 22 years. The acreage dedication agreements resulted in initial cash receipts and are being amortized on a units-of-production basis. The amortization rates are assessed on an annual basis for changes in estimated future production.

Deferred Oil Gathering Credits. In 2018, we entered into an agreement that dedicates crude oil from the majority of our Wattenberg Field acreage to the midstream provider's gathering lines and extends the term of the agreement through December 2029. The acreage dedication agreement resulted in an initial cash receipt and is being amortized over the life of the agreement.

The following table presents the amortization charges related to our deferred credits recognized on the consolidated statements of operations for the periods indicated:

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Crude oil, natural gas and NGL sales	$ 1,013	$ 439
Transportation, gathering and processing expenses	5,618	3,659
Lease operating expenses	2,015	935

NOTE 9 - LONG-TERM DEBT

Long-term debt consisted of the following as of the dates indicated:

	December 31,	
	2020	2019
	(in thousands)	
Senior Notes:		
1.125% Convertible Notes due September 2021:		
Principal amount	$ 200,000	$ 200,000
Unamortized discount	(6,295)	(14,763)
Unamortized debt issuance costs	(691)	(1,666)
Net of unamortized discount and debt issuance costs	193,014	183,571
6.125% Senior Notes due September 2024:		
Principal amount	400,000	400,000
Unamortized debt issuance costs	(3,632)	(4,611)
Net of unamortized debt issuance costs	396,368	395,389
6.25% Senior Notes due December 2025:		
Principal amount	102,324	—
Unamortized premium	880	—
Net of unamortized premium	103,204	—
5.75% Senior Notes due May 2026:		
Principal amount	750,000	600,000
Unamortized discount	(1,429)	—
Unamortized debt issuance costs	(6,595)	(5,734)
Net of unamortized discount and debt issuance costs	741,976	594,266
Total senior notes	1,434,562	1,173,226
Revolving Credit Facility:		
Revolving credit facility due May 2023	168,000	4,000
Total debt, net of unamortized discount, premium, and debt issuance costs	1,602,562	1,177,226
Less current portion of long-term debt	193,014	—
Total long-term debt	$ 1,409,548	$ 1,177,226

Senior Notes

2021 Convertible Notes. In September 2016, we issued $200 million of 1.125% convertible notes due September 15, 2021 (the "2021 Convertible Notes"). Interest is payable semi-annually in arrears on March 15 and September 15.

The 2021 Convertible Notes are convertible prior to March 15, 2021 only upon specified events and during specified periods and, thereafter, at any time, at an initial conversion rate of 11.7113 shares of our common stock per $1,000 principal amount of the 2021 Convertible Notes, which is equal to an initial conversion price of approximately $85.39 per share. The conversion rate is subject to adjustment upon certain events. Upon conversion, the 2021 Convertible Notes may be settled, at our sole election, in shares of our common stock, cash or a combination thereof. We have initially elected a combination settlement method to satisfy our conversion obligation, which allows us to settle the principal amount of the 2021 Convertible Notes in cash and to settle the excess conversion value, if any, in shares, as well as cash in lieu of fractional shares.

We may not redeem the 2021 Convertible Notes prior to their maturity date. If we undergo a "fundamental change", as defined in the indenture for the 2021 Convertible Notes, subject to certain conditions, holders of the 2021 Convertible Notes may require us to repurchase all or part of the 2021 Convertible Notes for cash at a price equal to 100 percent of the principal amount of the 2021 Convertible Notes to be repurchased, plus any accrued and unpaid interest. The occurrence of a fundamental change will also result in the 2021 Convertible Notes becoming convertible.

We allocated the gross proceeds of the 2021 Convertible Notes between the liability and equity components of the debt. The initial $160.5 million liability component was determined based on the fair value of similar debt instruments, excluding the conversion feature, priced on the same day we issued the 2021 Convertible Notes. The initial $39.5 million equity component represents the debt discount and was calculated as the difference between the fair value of the debt and the gross proceeds of the 2021 Convertible Notes. Approximately $4.8 million in costs associated with the issuance of the 2021 Convertible Notes were capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes. Based upon the Company's stock price of $20.53 per share as of December 31, 2020, the “if-converted” value of the 2021 Convertible Notes did not exceed the principal amount.

2024 Senior Notes. In September 2016, we issued $400 million aggregate principal amount of 6.125% senior notes due September 15, 2024. Interest is payable semi-annually on March 15 and September 15. Approximately $7.8 million in costs associated with the issuance of the 2024 Senior Notes were capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes. The 2024 Senior Notes are redeemable after September 15, 2020 at fixed redemption prices, currently 103.063 percent of the principal amount redeemed.

2025 Senior Notes. Upon completion of the SRC Acquisition in January 2020, we assumed $550 million aggregate principal amount of 6.25% senior notes due December 1, 2025 (the "2025 Senior Notes"). The 2025 Senior Notes were recorded at their approximate fair value of $555.5 million. The difference between the acquisition date fair value and the principal amount of the 2025 Senior Notes will be recognized as a reduction to interest expense over the remaining life of the notes. Interest is payable semi-annually on June 1 and December 1.

On January 17, 2020, we commenced an offer to repurchase the 2025 Senior Notes from the holders at 101 percent of the principal amount of the 2025 Senior Notes, together with any accrued and unpaid interest. Upon expiration of the repurchase offer on February 18, 2020, holders of $447.7 million of the outstanding 2025 Senior Notes accepted the redemption offer for a total redemption price of approximately $452.2 million, plus accrued and unpaid interest of $6.2 million. The fair value of the 2025 Senior Notes approximated the repurchase offer price, resulting in recognition of an immaterial loss on extinguishment of the repurchased notes. The repurchase was funded by proceeds from our revolving credit facility. An aggregate principal amount of approximately $102.3 million remains outstanding.

On and after December 1, 2020, the Company may redeem the remaining 2025 Senior Notes at a redemption price equal to a specified percentage of the principal amount of the redeemed notes (103.125% for 2021, 101.563% for 2022, and 100% for 2023 and thereafter, during the twelve-month period beginning on December 1 of each applicable year), plus accrued and unpaid interest.

2026 Senior Notes. In November 2017, we issued $600 million aggregate principal amount 5.75% senior notes due May 15, 2026 (the "2026 Senior Notes"). Interest is payable semi-annually on May 15 and November 15. Approximately $7.6 million in costs associated with the issuance of the 2026 Senior Notes were capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes.

In September 2020, we issued an additional $150 million aggregate principal amount of the 2026 Senior Notes at a price equal to 99 percent of par, which resulted in net proceeds of $146.7 million, after deducting the original issuance discount of $1.5 million and debt issuance costs of $1.8 million. The additional 2026 Senior Notes issued have the same terms and conditions as the existing 2026 Senior Notes.

The 2026 Senior Notes are redeemable after May 15, 2021 at fixed redemption prices beginning at 104.313 percent of the principal amount redeemed. At any time prior to May 15, 2021, we may redeem all or part of the 2026 Senior Notes at a make-whole price set forth in the indenture which generally approximates the present value of the redemption price at May 15, 2021 and remaining interest payments on the 2026 Senior Notes at the time of redemption.

Our wholly-owned subsidiary, PDC Permian, Inc., is a guarantor of our obligations under the 2021 Convertible Notes, the 2024 Senior Notes, the 2025 Senior Notes and the 2026 Senior Notes (collectively, the "Senior Notes").

The Senior Notes are senior unsecured obligations and rank senior in right of payment to our future indebtedness that is expressly subordinated to the notes; equal in right of payment to our existing and future indebtedness that is not so subordinated; effectively junior in right of payment to all of our secured indebtedness to the extent of the value of the assets securing such indebtedness; and structurally junior to all existing and future indebtedness (including trade payables) incurred by our non-guarantor subsidiaries.

Upon the occurrence of a "change of control," as defined in the indentures for the 2024 Senior Notes, 2025 Senior Notes and 2026 Senior Notes, holders will have the right to require us to repurchase all or a portion of the notes at a price equal to 101 percent of the aggregate principal amount of the notes repurchased, together with any accrued and unpaid interest to the date of purchase. In connection with certain asset sales, we may, under certain circumstances, be required to use the net cash proceeds of such asset sale to make an offer to purchase the notes at 100 percent of the principal amount, together with any accrued and unpaid interest to the date of purchase.

The indentures governing the 2024 Senior Notes, 2025 Senior Notes, and 2026 Senior Notes contain covenants that, among other things, limit our ability and the ability of our subsidiaries to incur additional indebtedness; pay dividends or make distributions on our stock; purchase or redeem stock or subordinated indebtedness; make investments; create certain liens; enter into agreements that restrict distributions or other payments by restricted subsidiaries to us; enter into transactions with affiliates; sell assets; consolidate or merge with or into other companies or transfer all or substantially of our assets; and create unrestricted subsidiaries. As of December 31, 2020, we were in compliance with all covenants related to the Senior Notes.

Revolving Credit Facility

In May 2018, we entered into a Fourth Amended and Restated Credit Agreement (the “Restated Credit Agreement”). The Restated Credit Agreement provides for a maximum credit amount of $2.5 billion. The amount we may borrow under the Restated Credit Agreement is subject to certain limitations. As a result of closing the SRC Acquisition, the borrowing base on our revolving credit facility increased to $2.1 billion and we elected to increase the aggregate commitment amount under our revolving credit facility to $1.7 billion. In October 2020, as part of our fall 2020 semi-annual redetermination, the borrowing base was reduced to $1.6 billion, with a corresponding automatic reduction to our elected commitment level of $1.6 billion. As of December 31, 2020 and 2019, availability under our revolving credit facility was $1.4 billion and $1.3 billion, respectively.

The revolving credit facility is available for working capital requirements, capital investments, acquisitions, to support letters of credit and for general corporate purposes. The borrowing base is based on, among other things, the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests. The borrowing base is subject to a semi-annual redetermination on November 1 and May 1 based upon quantification of our reserves at June 30 and December 31, and is also subject to a redetermination upon the occurrence of certain events. Substantially all of our crude oil and natural gas properties have been mortgaged or pledged as security for our revolving credit facility.

The outstanding principal amount under the revolving credit facility accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greatest of the administrative agent's prime rate, the federal funds rate plus a premium and the rate for dollar deposits in the London interbank market (“LIBOR”) for one month plus a premium) or, at our election, a rate equal to LIBOR for certain time periods. Additionally, commitment fees, interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. As of December 31, 2020, the applicable interest margin is 0.75 percent for the alternate base rate option or 1.75 percent for the LIBOR option, and the unused commitment fee is 0.375 percent. Principal payments are generally not required until the revolving credit facility expires in May 2023 unless the borrowing base falls below the outstanding balance.

The revolving credit facility contains various restrictive covenants and compliance requirements, which include, among other things: (i) maintenance of certain financial ratios, as defined per the revolving credit facility, including maintenance of minimum current ratio of 1.0:1.0 and not exceed a maximum leverage ratio of 4.0:1.0; (ii) restrictions on the payment of cash dividends; (iii) limits on the incurrence of additional indebtedness; (iv) prohibition on the entry into commodity hedges exceeding a specified percentage of our expected production; and (v) restrictions on mergers and dispositions of assets. As of December 31, 2020, we were in compliance with all the revolving credit facility covenants.

As of December 31, 2020 and 2019, debt issuance costs related to our revolving credit facility were $8.1 million and $8.9 million, respectively, and are included in other assets line on the consolidated balance sheets.

NOTE 10 - LEASES

We adopted ASU 2016-02, *Leases*, effective January 1, 2019. We have operating leases for office space and compressors and finance leases for vehicles. Our leases have remaining lease terms ranging from one to five years. The vehicle leases include options to renew for up to four years. Lease payments associated with vehicle leases also include a contractually stated residual value guarantee.

The following table presents the components of lease costs for the periods indicated:

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Operating lease costs [(1)]	$ 7,983	$ 4,917
Finance lease costs:		
Amortization of ROU assets	1,812	1,961
Interest on lease liabilities	179	252
Total finance lease costs	1,991	2,213
Short-term lease costs	193,756	170,064
Total lease costs	$ 203,730	$ 177,194

(1) The majority of our operating leases relate to the operation or completion of our wells. Therefore, the lease costs presented in the table above represent the total gross costs the Company incurs, which are not comparable to the Company's net costs recorded to the consolidated statements of operations, consolidated statements of cash flows or capitalized in the consolidated balance sheets, as amounts therein are reflected net of amounts billed to working interest partners.

Our operating lease costs are recorded in lease operating expenses or general and administrative expense and our finance lease costs are recorded in DD&A expense and interest expense. Our short-term lease costs include amounts that are capitalized as part of the cost of another asset and are recorded as properties and equipment or recognized as expense.

The following table presents the balance sheet classification and other information regarding our leases as of:

	Consolidated Balance Sheet Line Item	December 31, 2020	December 31, 2019
		(in thousands)	
Operating Leases:			
Operating lease ROU assets	Other assets	$ 11,722	$ 14,926
Operating lease obligation - short-term	Other accrued expenses	6,520	4,159
Operating lease obligation - long-term	Other liabilities	9,061	12,944
Total operating lease liabilities		$ 15,581	$ 17,103
Finance Leases:			
Finance lease ROU assets	Properties and equipment, net	$ 3,189	$ 4,637
Finance lease obligation - short-term	Other accrued expenses	1,466	1,767
Finance lease obligation - long-term	Other liabilities	1,702	2,835
Total finance lease liabilities		$ 3,168	$ 4,602
Weighted-average remaining lease term (years)			
Operating leases		3.07	4.28
Finance leases		2.58	3.17
Weighted-average discount rate			
Operating leases		4.8 %	5.0 %
Finance leases		4.5 %	5.0 %

Maturity of lease liabilities by year and in the aggregate, under operating and financing leases with terms of one year or more, as of December 31, 2020 consist of the following:

	Operating Leases	Finance Leases	Total
		(in thousands)	
2021	$ 7,055	$ 1,557	$ 8,612
2022	5,516	933	6,449
2023	1,559	655	2,214
2024	950	139	1,089
2025	950	10	960
Thereafter	748	—	748
Total lease payments	16,778	3,294	20,072
Less: Interest and discount	(1,197)	(126)	(1,323)
Present value of lease liabilities	$ 15,581	$ 3,168	$ 18,749

NOTE 11 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our working interests in crude oil and natural gas properties:

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in thousands)	
Beginning balance	$ 127,251	$ 115,021
Obligations incurred with development activities and other	6,494	4,605
Obligations incurred with acquisition	47,673	2,882
Accretion expense	10,072	6,117
Revisions in estimated cash flows	4,742	28,991
Obligations discharged with asset retirements	(28,888)	(23,426)
Obligations discharged with divestitures	(774)	(6,939)
Balance at December 31	166,570	127,251
Current portion	(33,933)	(32,200)
Long-term portion	$ 132,637	$ 95,051

Our estimated asset retirement obligations liability is based on historical experience in plugging and abandoning wells, estimated economic lives and estimated plugging, abandonment and surface reclamation costs considering federal and state regulatory requirements in effect at that time. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations liability, a corresponding adjustment is made to the properties and equipment balance. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as accretion expense. Short-term asset retirement obligations are included in other accrued expenses in our consolidated balance sheets.

The revisions in estimated cash flows for 2019 were primarily due to increases in the estimated surface reclamation costs to obtain final well pad reclamation approval from the applicable regulatory agencies.

NOTE 12 - COMMITMENTS AND CONTINGENCIES

The following table presents gross volume information related to our long-term firm transportation, sales and processing agreements for pipeline capacity and water delivery and disposal commitments:

	Year Ending December 31,							
Area	2021	2022	2023	2024	2025	Thereafter	Total	Expiration Date
Natural gas (MMcf)								
Wattenberg Field	64,014	64,014	64,014	64,189	52,045	18,779	327,055	August 31, 2026
Delaware Basin	31,025	9,125	9,125	9,150	9,125	45,650	113,200	December 31, 2030
Gas Marketing	1,777	1,183	—	—	—	—	2,960	August 31, 2022
Total	96,816	74,322	73,139	73,339	61,170	64,429	443,215	
Crude oil (MBbls)								
Wattenberg Field	17,002	15,330	11,655	9,882	9,855	6,561	70,285	August 31, 2026
Delaware Basin	8,030	8,030	8,030	—	—	—	24,090	December 31, 2023
Total	25,032	23,360	19,685	9,882	9,855	6,561	94,375	
Water (MBbls)								
Wattenberg Field	6,207	6,207	6,207	6,223	—	—	24,844	December 31, 2024
Total	6,207	6,207	6,207	6,223	—	—	24,844	
Dollar commitment *(in thousands)*	$ 135,435	$ 114,472	$ 95,082	$ 68,175	$ 56,174	$ 47,489	$ 516,827	

Firm Transportation and Processing Agreements. We enter into contracts that provide firm transportation and processing on pipeline systems through which we transport or sell crude oil and natural gas. Satisfaction of the volume requirements includes volumes produced by us and purchased from third parties and produced by other third-party working, royalty and overriding royalty interest owners, whose volumes we market on their behalf. Our consolidated statements of operations reflect our share of these firm transportation and processing costs. These contracts require us to pay these transportation and processing charges whether or not the required volumes are delivered. We may from time to time find ourselves unable to market our commodities at prices acceptable to us, or at all, which could cause us to be unable to meet these obligations. In such cases, we may be subject to fees, minimum margins or other payments.

Facilities Expansion Agreements. We entered into two facilities expansion agreements with our primary midstream provider to expand and improve its natural gas gathering pipelines and processing facilities in the Wattenberg Field. The midstream provider completed and turned on line the first of the two 200 MMcfd cryogenic plants in August 2018 and the second plant was completed in August 2019. We are bound to the volume requirements in these agreements on the first day of the calendar month following the actual in-service date of the relevant plant. Both agreements require baseline volume commitments, consisting of our gross wellhead volume delivered in November 2016 to this midstream provider, and incremental wellhead volume commitments of 51.75 MMcfd and 33.5 MMcfd for the first and second agreements, respectively, for seven years. In addition, as a result of the SRC Acquisition, we are subject to substantially similar facilities expansion agreements with the same primary midstream provider of 46.4 MMcfd and 43.8 MMcfd, respectively. We may be required to pay shortfall fees for any volumes under 98.2 MMcfd and 77.3 MMcfd incremental commitments. Any shortfall in these volume commitments may be offset by other producers' volumes sold to the midstream provider that are greater than a certain total baseline volume. We are also required for the first three years of the contracts to guarantee a certain target profit margin to the midstream provider on these incremental volumes. The actual shortfall in target profit margin incurred, which we guaranteed to our midstream provider, was included as part of contract assets as part of Other assets on the consolidated balance sheets.

Firm sales agreement. In May 2018, we entered into a firm sales agreement that is effective from June 2018 through December 2023 with an integrated marketing company for our crude oil production in the Delaware Basin. Contracted volumes are currently 24,000 barrels of crude oil per day and decrease over time to 22,000 barrels per day. This agreement is expected to provide price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices.

Crude Oil, Natural Gas and NGLs Sales. For the years ended December 31, 2020 and 2019, amounts related to long-term transportation volumes, net to our interest, in the table above were $22.2 million and $50.1 million, respectively, and were netted against our crude oil and natural gas sales. In addition, amounts related to long-term transportation volumes recorded in transportation, gathering and processing expenses amounted to $15.7 million and $1.9 million for the years ended December 31, 2020 and 2019, respectively.

Litigation and Legal Items. We are involved in various legal proceedings. We review the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in our best interests. We have provided the necessary estimated accruals in the accompanying consolidated balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination. We conduct periodic reviews and simulated drills to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, we are not aware of any material environmental claims existing as of December 31, 2020 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws or other environmental liabilities will not be discovered on our properties. Accrued environmental liabilities are recorded in other accrued expenses in the consolidated balance sheets.

In recent years, we have been executing a program to plug and abandon certain of our older vertical wells in the Wattenberg Field. A self-audit of final reclamation activities associated with site retirements, which we concluded in 2019, identified deficiencies, including incomplete documentation and agency submittals, inadequate plant growth and incomplete earthwork. In December 2019, we formally disclosed these deficiencies to the Colorado Oil and Gas Conservation Commission ("COGCC") and are working to close this backlog of site reclamation work. On August 19, 2020, COGCC issued to PDC a Notice of Alleged Violation ("NOAV") citing a failure to comply with reclamation requirements at multiple locations. During 2020, we similarly assessed and identified deficiencies in reclamation activities at sites acquired through the SRC Acquisition. We do not believe potential penalties and other expenditures associated with the deficiencies disclosed to the COGCC and the resulting NOAV, nor any potential future disclosure of deficiencies associated with reclamation of sites acquired in the SRC Acquisition, will have a material effect on our financial condition or results of operations, but they may exceed $300,000.

As part of our integration activities over the facilities acquired through the SRC Acquisition, we are in the process of conducting a comprehensive air quality compliance audit. We do not believe potential penalties and other expenditures associated with deficiencies identified through the audit will have a material effect on our financial condition or results of operations, but they may exceed $300,000.

Clean Air Act Agreement and Related Consent Decree. In June 2017, following our receipt of a 2015 Clean Air Act information request from the EPA and a 2015 compliance advisory from the Colorado Department of Public Health and Environment's (“CDPHE”) Air Pollution Control Division, the U.S. Department of Justice, on behalf of the EPA and the state of Colorado, filed a complaint against us in the U.S. District Court for the District of Colorado, claiming that we failed to operate and maintain certain condensate collection facilities at 65 facilities so as to minimize leakage of volatile organic compounds in compliance with applicable law.

In October 2017, we entered into a consent decree to resolve the lawsuit and the compliance advisory. Pursuant to the consent decree, we agreed to implement a variety of operational enhancements and environmental mitigations and similar projects, including vapor control system modifications and verification, increased inspection and monitoring and installation of tank pressure monitors. While many of those actions are complete, some requirements will continue until the consent decree is terminated.

In addition, as a result of the SRC Acquisition, we are subject to the obligations and requirements of a 2018 Compliance Order on Consent ("COC") entered into by SRC with CDPHE, applicable to certain SRC oil and gas production facilities. The CDPHE revised the COC to make the inspection and monitoring requirements, among others, consistent with those contained in our consent decree.

Since the consent decree took effect, and more recently was expanded to include the COC, we have timely implemented the various programs that meet its requirements. Over the course of this execution, we have identified certain immaterial deficiencies in our implementation of the programs. We report these immaterial deficiencies to the appropriate authorities and remediate them promptly. We do not believe that the penalties and expenditures associated with the consent decree, including any sanctions associated with these deficiencies, will have a material effect on our financial condition or results of operations, but they may exceed $300,000.

Further, we could be the subject of other enforcement actions by regulatory authorities in the future relating to our past, present or future operations.

NOTE 13 - COMMON STOCK

Stock-Based Compensation Plans

2018 Equity Incentive Plan. In May 2020, our stockholders approved an amendment to increase the number of shares of our common stock reserved for issuance pursuant to our long-term equity compensation plan for employees and non-employee directors (the “2018 Plan”) from 1,800,000 to 7,050,000. The 2018 Plan was approved in May 2018 and expires in March 2028. The capital stock available for issuance under the 2018 Plan shall be shares of the Company’s authorized but unissued common stock or previously issued common stock that has been reacquired by the Company. Additionally, to the extent that an award under the 2018 Plan, in whole or in part, is canceled, expired, forfeited, settled in cash or otherwise terminated without delivery of shares, the shares are not deemed to have been delivered under the 2018 Plan and remain available for issuance. Any shares withheld for taxes cannot be recycled under this plan. Awards may be issued in the form of options, stock appreciation rights ("SARs"), restricted stock, restricted stock units ("RSUs"), performance stock units ("PSUs") and other stock-based awards. Awards may vest over periods of continued service or upon the satisfaction of performance conditions set at the discretion of the Compensation Committee of the board of directors (the "Compensation Committee"), with a minimum one-year vesting period applicable to most awards. With regard to SARs and options, awards have a maximum exercisable period of ten years. As of December 31, 2020, there were 5,204,837 shares available for grant under the 2018 Plan.

2010 Long-Term Equity Compensation Plan. Our Amended and Restated 2010 Long-Term Equity Compensation Plan, which was approved by stockholders in 2013 (the "2010 Plan"), remains outstanding and we may continue to use the 2010 Plan to grant awards. No awards may be granted under the 2010 Plan on or after June 5, 2023. As of December 31, 2020, there were 189,154 shares available for grant under the 2010 Plan.

2015 SRC Equity Incentive Plan. Pursuant to the closing of the SRC Acquisition, SRC granted 155,928 PSUs to certain SRC executives under the 2015 SRC Equity Incentive Plan (the “2015 SRC Plan”). These PSUs (the “SRC PSUs”) were granted prior to the consummation of the merger, were assumed and converted into PDC PSUs at a rate of 0.158 per share and remain subject to the same terms and conditions (including performance-vesting terms) that applied immediately prior to the closing of the SRC Acquisition. The PSUs will result in a payout between zero and 200 percent of the target PSUs awarded. As of December 31, 2020, there were no shares available for grant under the 2015 SRC Plan.

The following table provides a summary of the impact of our outstanding stock-based compensation plans on the results of operations for the periods presented:

	Year Ended December 31,		
Stock-based compensation expense included in:	**2020**	**2019**	**2018**
		(in thousands)	
General and administrative expense	$ 21,182	$ 22,754	$ 20,848
Lease operating expenses	1,018	1,083	934
Total stock-based compensation expense	$ 22,200	$ 23,837	$ 21,782

Restricted Stock Units

The Company grants to executive officers and employees, time-based RSUs, which vest ratably over a three-year service period. The fair value for these time-based RSUs is based on the market price of our common stock on the grant date and are recognized ratably over the requisite service period. The time-based RSUs generally vest ratably on each anniversary following the grant date provided that a participant is continuously employed.

The following table presents the changes in non-vested time-based RSUs, including executive officers, during the year ended December 31, 2020:

	Shares	**Weighted-Average Grant Date Fair Value per Share**
Non-vested at December 31, 2019	795,926	$ 45.51
Granted	1,203,108	11.98
Vested	(534,610)	38.08
Forfeited	(313,454)	22.62
Non-vested at December 31, 2020	1,150,970	20.14

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/Year Ended December 31,		
	2020	**2019**	**2018**
		(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$ 7,312	$ 11,652	$ 12,282
Total intrinsic value of time-based awards non-vested	23,629	20,829	18,404
Market price per share as of December 31,	20.53	26.17	29.76
Weighted-average grant date fair value per share	11.98	40.34	50.69

Total compensation cost related to non-vested time-based awards and not yet recognized in our consolidated statements of operations as of December 31, 2020 was $13.0 million. This cost is expected to be recognized over a weighted-average period of 1.8 years.

Performance Stock Units

The Company grants to certain executive officers PSUs which are subject to market-based vesting criteria as well as a three-year service period. The market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved. The fair value of the market-based PSUs is amortized ratably over the requisite service period. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

The Compensation Committee awarded a total of 368,077 market-based PSUs to our executive officers during 2020. In addition to continuous employment, the vesting of these PSUs is contingent on a combination of absolute stock performance and our total stockholder return ("TSR"), which is essentially our stock price change including any dividends over a three-year period ending on December 31, 2022, as compared to the TSR of a group of peer companies over the same period. The PSUs will result in a payout between zero and 250 percent of the target PSUs awarded.

The grant-date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. The expected term of the awards was based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the life of the award. The expected volatility was based on our common stock historical volatility.

The following table summarizes the key assumptions and related information used to determine the grant-date fair value of performance stock units awarded during the periods presented:

	Year Ended December 31,		
	2020	2019	2018
Expected term of award (in years)	3	3	3
Risk-free interest rate	1.4 %	2.5 %	2.4 %
Expected volatility	46.6 %	41.4 %	42.3 %
Weighted-average grant date fair value per share	$ 33.52	$ 56.68	$ 69.98

SRC Performance Stock Units. The terms of the SRC PSUs are substantially the same as those of the PDC PSUs, except that the SRC PSUs do not require continuous employment and the performance period associated with the awards of January 1, 2019 through December 31, 2021 predates the grant date. The fair value of the SRC PSU awards was determined on the grant date of January 13, 2020 using the Monte Carlo pricing model using the following assumptions:

	Year Ended December 31, 2020
Expected term of awards (in years)	2
Risk-free interest rate	1.6 %
Expected volatility	56.9 %
Weighted-average grant date fair value per share	$ 33.35

The expected term of the awards is based on the number of years from the grant date through the end of the performance period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant, extrapolated to approximate the life of the awards. The expected volatility was based on our common stock historical volatility, as well as that of our peer group.

The following table presents the change in non-vested market-based awards, including SRC PSUs, during the year ended December 31, 2020:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2019	221,142	$ 61.61
Granted	524,005	30.29
Vested	(156,003)	38.59
Forfeited	(89,597)	46.43
Non-vested at December 31, 2020	499,547	38.66

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/Year Ended December 31,		
	2020	2019	2018
	(in thousands, except per share data)		
Total intrinsic value of market-based awards vested	$ 1,736	$ 530	$ 620
Total intrinsic value of market-based awards non-vested	10,256	5,787	3,063
Market price per share as of December 31,	20.53	26.17	29.76
Weighted-average grant date fair value per share	30.29	56.68	69.98

Total compensation cost related to non-vested market-based awards not yet recognized in our consolidated statements of operations as of December 31, 2020 was $7.6 million. This cost is expected to be recognized over a weighted-average period of 1.7 years.

Stock Appreciation Rights

The SARs vest ratably over a three-year period and may generally be exercised at any point after vesting through ten years from the date of issuance. Pursuant to the terms of the awards, upon exercise, the executive officers will receive, in shares of common stock, the excess of the market price of the award on the date of exercise over the market price of the award on the date of issuance. All outstanding SARs as of December 31, 2020 have vested and the related compensation cost has been fully recognized. As of December 31, 2020, there were 210,675 SARs outstanding and exercisable which have a weighted-average exercise price of $49.45 and average remaining contractual term of 3.3 years. Outstanding and exercisable SARs have no intrinsic value as of December 31, 2020.

Preferred Stock

We are authorized to issue 50,000,000 shares of preferred stock, par value $0.01 per share, which may be issued in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by the board of directors from time to time. Through December 31, 2020, no shares of preferred stock have been issued.

Stock Repurchase Program

In April 2019, the board of directors approved the acquisition of up to $200 million of our outstanding common stock, depending on market conditions (the "Stock Repurchase Program"). Effective upon the closing of the SRC Acquisition, our board of directors approved an increase and extension to the Stock Repurchase Program from $200 million to $525 million. Repurchases under the Stock Repurchase Program can be made in open markets at our discretion and in compliance with safe harbor provisions, or in privately negotiated transactions. The Stock Repurchase Program does not require any specific number of shares to be acquired, and can be modified or discontinued by the board of directors at any time. Pursuant to the Stock Repurchase Program, we repurchased 1.3 million shares and 4.7 million shares of outstanding common stock at a cost of $23.8 million and $154.4 million during the years ended December 31, 2020 and 2019, respectively. We suspended the program in March 2020. However, we reinstated the program in late February 2021. Repurchases may extend until December 31, 2023. As of December 31, 2020, $346.8 million of our outstanding common stock remained available for repurchase under the Stock Repurchase Program.

NOTE 14 - INCOME TAXES

The table below presents the components of our provision for income tax (expense) benefit for the years presented:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Current:			
Federal	$ 1,592	$ 1,366	$ 887
State	(220)	(300)	(188)
Total current income tax benefit	1,372	1,066	699
Deferred:			
Federal	5,460	4,507	(1,986)
State	1,070	(2,251)	(4,119)
Total deferred income tax (expense) benefit	6,530	2,256	(6,105)
Income tax (expense) benefit	$ 7,902	$ 3,322	$ (5,406)

The following table presents a reconciliation of the federal statutory rate to the effective tax rate related to our (expense) benefit for income taxes:

	Year Ended December 31,		
	2020	2019	2018
Federal statutory tax rate	21.0 %	21.0 %	21.0 %
State income tax, net	3.0	3.6	(6.4)
Federal tax credits	—	(3.3)	(52.1)
Effect of state income tax rate changes	0.2	(6.4)	6.7
Change in valuation allowance	(22.1)	(0.6)	45.5
Non-deductible compensation	(0.6)	(5.0)	21.8
Non-deductible acquisition costs	(0.1)	(2.3)	—
Non-deductible government relations	(0.1)	(1.0)	31.8
Other non-deductible items	—	(0.5)	4.9
Other	(0.2)	—	(0.4)
Effective tax rate	1.1 %	5.5 %	72.8 %

The effective income tax rates for 2020 and 2019 were 1.1 percent and 5.5 percent on the respective pre-tax losses. The effective tax rate of 1.1 percent for 2020 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21 percent to the pre-tax loss due to the full valuation allowance in effect at December 31, 2020. The effective tax rate of 5.5 percent for 2019 differs from the statutory U.S. federal income tax rate of 21 percent due to state income taxes, non-deductible lobbying expenses, stock-based compensation and nondeductible officers’ compensation.

Tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities as of the dates indicated:

	December 31, 2020	December 31, 2019
	(in thousands)	
Deferred tax assets:		
Deferred compensation	$ 10,472	$ 9,905
Asset retirement obligations	39,371	30,993
Federal NOL carryforward	97,880	22,965
State NOL and tax credit carryforwards, net	21,034	9,508
Federal tax - credit carryforwards	3,059	4,448
Net change in fair value of unsettled commodity derivatives	18,351	—
Prepaid revenue	4,364	4,874
Other	5,741	3,887
Valuation allowance	(165,575)	(3,775)
Total gross deferred tax assets	34,697	82,805
Deferred tax liabilities:		
Properties and equipment	33,183	268,234
Net change in fair value of unsettled commodity derivatives	—	6,841
Convertible debt	1,514	3,571
Total gross deferred tax liabilities	34,697	278,646
Net deferred tax liability	$ —	$ 195,841

The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At each reporting period, management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies and projected future taxable income in making this assessment. As previously noted, we recorded impairments totaling $882.4 million in 2020. These impairments resulted in three years of cumulative historical pre-tax losses and a net deferred tax asset position. The impairment losses were a key consideration that led us to continue to provide a valuation allowance against our net deferred tax assets as of December 31, 2020 since we cannot conclude that it is more likely than not that our net deferred tax asset will be fully realized in future periods. As a result, we recorded a $7.9 million benefit in 2020 to increase our deferred tax valuation allowance to $165.6 million and reduce the carrying value of our deferred tax assets to zero.

As of December 31, 2020, we have estimated net operating loss carryfowards ("NOLs") for federal income tax purposes of $466 million, of which $304 million was generated before January 1, 2018 and is not subject to the 80 percent limitation of taxable income. Such NOLs will expire beginning 2033. In 2016, we acquired a federal NOL of $60.1 million as a component of our acquisition in the Delaware Basin that will begin to expire in 2033. Also, we acquired a federal NOL of $232.5 million as component of the SRC Acquisition that will begin to expire in 2037. The federal NOLs acquired as part of our acquisition in the Delaware Basin and the SRC Acquisition are subject to an annual limitation of $15.1 million and $16.1 million, respectively, as both acquisitions constitute a change of ownership as defined under Internal Revenue Service ("IRS") Code Section 382.

As of December 31, 2020, we have state NOL carryforwards of $494.8 million that begin to expire in 2029 and state credit carryforwards of $3.7 million that begin to expire in 2022.

Unrecognized tax benefits and related accrued interest and penalties were immaterial for the three-year period ended December 31, 2020. The statutes of limitations for most of our state tax jurisdictions are open for tax year 2017 forward. As of December 31, 2020, there is no liability for unrecognized income tax benefits.

We are subject to the following material taxing jurisdictions: U.S., Colorado, West Virginia, and Texas. As of December 31, 2020, we are current with our income tax filings in all applicable state jurisdictions and are not currently under any state income tax examinations. We are open to federal and state tax audits until the applicable statutes of limitations expire, however, the ability for the tax authority to adjust the NOL will continue until three years after NOL is utilized. The statute of limitations has expired for all federal and state returns filed for periods ending before 2016. The IRS has partially accepted our 2019 federal income tax return. The 2019 federal tax return is in the IRS Compliance Assurance Program (the "CAP Program") post-filing review process, with no significant tax adjustments currently proposed. We continue to voluntarily participate in the IRS CAP Program for the review of our 2020 tax year. Participation in the IRS CAP Program has enabled us to have minimal uncertain tax benefits associated with our federal tax return filings.

NOTE 15 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net earnings by the weighted-average number of common shares outstanding for the period. Diluted earnings per share is similarly computed except that the denominator includes the effect, using the treasury stock method, of unvested equity-based employee awards, convertible notes and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents our weighted-average basic and diluted shares outstanding for the periods presented:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Weighted-average common shares outstanding - basic	98,251	64,032	66,059
Dilutive effect of:			
RSUs and PSUs	—	—	173
Other equity-based awards	—	—	71
Weighted-average common shares and equivalents outstanding - diluted	98,251	64,032	66,303

We reported a net loss for the years ended December 31, 2020 and 2019. As a result, our basic and diluted weighted-average common shares outstanding were the same for those periods because the effect of the common share equivalents was anti-dilutive.

The following table presents the weighted-average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect for the periods presented:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:			
RSUs and PSUs	1,707	989	145
Other equity-based awards	229	302	109
Total anti-dilutive common share equivalents	1,936	1,291	254

The 2021 Convertible Notes give the holders, at our election, the right to convert the aggregate principal amount into 2.3 million shares of our common stock at a conversion price of $85.39 per share. The 2021 Convertible Notes were not included in the diluted earnings per share calculation using the treasury stock method for any periods presented as the average market price of our common stock did not exceed the conversion price.

NOTE 16 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

	Year Ended December 31,		
	2020	2019	2018 (1)
		(in thousands)	
Supplemental cash flow information:			
Cash payments (receipts) for:			
Interest, net of capitalized interest	$ 75,506	$ 57,439	$ 55,586
Income taxes	9	(1,167)	(6,719)
Non-cash investing and financing activities:			
Issuance of common stock for acquisition of crude oil and natural gas properties, net	1,009,015	—	—
Change in accounts payable related to capital expenditures	(28,676)	(68,246)	36,328
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	54,984	29,533	37,136
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 9,246	$ 5,301	$ —
Operating cash flows from finance leases	156	253	—
ROU assets obtained in exchange for lease obligations:			
Operating leases	$ 4,305	$ 1,428	$ —
Finance leases	703	2,323	—

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(1) *As we have elected the modified retrospective method of adoption for ASU 2016-02, Leases, cash flows related to lease liabilities have not been restated for 2018.*

CRUDE OIL AND NATURAL GAS INFORMATION - UNAUDITED

Net Proved Reserves

All of our crude oil, natural gas and NGLs reserves are located in the United States. We utilize the services of independent petroleum engineers to estimate our crude oil, natural gas and NGLs reserves. As of December 31, 2020, 2019 and 2018 (as applicable), all of our estimates of proved reserves for the Wattenberg Field were based on reserve reports prepared by Ryder Scott and all of our estimates for proved reserves for the Delaware Basin were based on reserve reports prepared by NSAI. These reserve estimates have been prepared in compliance with guidelines established by the SEC and FASB. All of our proved undeveloped reserves conform to the SEC five-year rule requirement that they be scheduled to be drilled within five years of each location's initial booking date.

Reserve estimates are based on an unweighted arithmetic average of commodity prices during the preceding 12-month period, using the closing prices on the first day of each month, as required by the SEC. The table below presents the index prices for our estimated reserves, by commodity, as of the dates indicated:

	Average Benchmark Prices		
December 31,	Crude Oil (per Bbl) (1)	Natural Gas (per MMBtu) (1)	NGLs (per Bbl) (2)
2020	$ 39.57	$ 1.99	$ 39.57
2019	55.69	2.58	55.69
2018	65.56	3.10	65.56

(1) Our benchmark prices for crude oil and natural gas are WTI and Henry Hub, respectively.
(2) For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.

The netted back price used to estimate our reserves, by commodity, are presented below.

	Price Used to Estimate Reserves (1)		
December 31,	Crude Oil (per Bbl)	Natural Gas (per MMBtu)	NGLs (per Bbl)
2020	$ 37.52	$ 1.26	$ 10.55
2019	52.63	1.50	12.21
2018	61.14	2.15	23.04

(1) These prices are based on the index prices and are net of basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the respective commodity, including consideration for contracts that are effective as of December 31, 2020.

The following tables present the changes in our estimated quantities of proved reserves:

	Crude Oil, Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved reserves, January 1, 2018	154,842	1,154,294	105,692	452,917
Revisions of previous estimates	26,548	94,738	12,674	55,011
Extensions, discoveries and other additions	8,786	61,750	8,868	27,946
Acquisition of reserves	19,644	148,674	15,936	60,360
Dispositions	(2,507)	(35,750)	(2,656)	(11,121)
Production	(16,964)	(88,017)	(8,527)	(40,160)
Proved reserves, December 31, 2018	190,349	1,335,689	131,987	544,953
Revisions of previous estimates	25,875	328,290	31,559	112,147
Extensions, discoveries and other additions	1,056	10,262	1,519	4,285
Acquisition of reserves	553	4,558	448	1,761
Dispositions	(1,412)	(5,052)	(614)	(2,868)
Production	(19,166)	(115,950)	(10,923)	(49,414)
Proved reserves, December 31, 2019	197,255	1,557,797	153,976	610,864
Revisions of previous estimates	(41,089)	(272,243)	(14,774)	(101,237)
Extensions, discoveries and other additions	812	2,991	324	1,635
Acquisition of reserves	80,590	795,977	81,770	295,023
Dispositions	(2,116)	(17,711)	(1,776)	(6,844)
Production	(23,720)	(165,637)	(17,042)	(68,368)
Proved reserves, December 31, 2020	211,732	1,901,174	202,478	731,073
Proved developed reserves, as of:				
December 31, 2018	61,821	443,151	43,856	179,535
December 31, 2019	66,211	554,234	55,411	213,994
December 31, 2020	86,330	860,877	91,702	321,512
Proved undeveloped reserves, as of:				
December 31, 2018	128,528	892,538	88,131	365,418
December 31, 2019	131,044	1,003,563	98,565	396,870
December 31, 2020	125,402	1,040,297	110,776	409,561

	Developed	Undeveloped	Total
		(MBoe)	
Proved reserves, January 1, 2018	142,971	309,946	452,917
Revisions of previous estimates	6,284	48,727	55,011
Extensions, discoveries and other additions	7,874	20,072	27,946
Acquisition of reserves	8,758	51,602	60,360
Dispositions	(4,486)	(6,635)	(11,121)
Production	(40,160)	—	(40,160)
Undeveloped reserves converted to developed	58,294	(58,294)	—
Proved reserves, December 31, 2018	179,535	365,418	544,953
Revisions of previous estimates	27,452	84,695	112,147
Extensions, discoveries and other additions	4,285	—	4,285
Acquisition of reserves	441	1,320	1,761
Dispositions	(474)	(2,394)	(2,868)
Production	(49,414)	—	(49,414)
Undeveloped reserves converted to developed	52,169	(52,169)	—
Proved reserves, December 31, 2019	213,994	396,870	610,864
Revisions of previous estimates	(8,634)	(92,603)	(101,237)
Extensions, discoveries and other additions	1,635	—	1,635
Acquisition of reserves	125,180	169,843	295,023
Dispositions	(2,487)	(4,357)	(6,844)
Production	(68,368)	—	(68,368)
Undeveloped reserves converted to developed	60,192	(60,192)	—
Proved reserves, December 31, 2020	321,512	409,561	731,073

2020 Activity. During 2020, we increased proved reserves by 120.2 MMBoe, or 20 percent, relative to December 31, 2019. The increase in proved reserves was primarily the result of the SRC Acquisition, partially offset by downward revisions of previous estimates. In 2020, we produced 68.4 MMBoe.

Revisions of Previous Estimates- Proved Developed Reserves. Proved developed reserves experienced a net negative revision of 8.6 MMBoe primarily due to a decrease of 28.2 MMBoe as a result of lower average prices for crude oil, natural gas and NGLs for 2020. The negative revisions were partially offset by a 14.3 MMBoe increase associated with lower operating costs and a 5.3 MMBoe increase related to performance revisions and other items.

Revisions of Previous Estimates- PUDs. Net downward revisions to our previous PUD reserves estimates of 92.6 MMBoe were due to (i) 266.7 MMBoe related to PUD locations that were reclassified to unproven reserves due to drilling schedule changes, (ii) a reduction of 25.5 MMBoe of reserves primarily related to DUCs which were not completed within five years of their initial recording in accordance with SEC rules, and (iii) 11.3 MMBoe related to downward pricing adjustments due to lower average prices for crude oil, natural gas and NGLs for 2020. Drilling schedule changes resulted from PUD downgrades associated with lower realized prices and revised drilling plans following the completion of the SRC Acquisition. The negative revisions were partially offset by a 199.9 MMBoe increase related to additional locations on proved acreage resulting from our drilling plan and 11.0 MMBoe related to performance revisions and other items.

Extensions, Discoveries and Other Additions- Proved Developed Reserves. Developed activity for 2020 included the addition of 1.6 MMBoe of developed reserves related to two gross newly-drilled wells in the Delaware Basin.

Extensions, Discoveries and Other Additions- PUDs. There were no extensions, discoveries or other additions for PUD reserves during 2020.

Acquisitions of Reserves- Proved Developed Reserves. Proved developed reserves acquired primarily pertain to the SRC Acquisition completed in January 2020.

Acquisitions of Reserves- PUDs. Proved undeveloped reserves acquired primarily pertain to the SRC Acquisition completed in January 2020.

Dispositions- Proved Developed Reserves. Dispositions of 2.5 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

Dispositions- PUDs. Dispositions of 4.4 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

At December 31, 2019, we projected a PUD reserve conversion rate of 26 percent for 2020. During 2020, our actual conversion rate was 11 percent primarily due to a change in our drilling plan in April 2020 relating to decreased commodity prices and crude oil demand which resulted in a smaller number of wells turned-in-line than originally anticipated. We converted 60.2 MMBoe of PUD reserves at December 31, 2019 to proved developed reserves as of December 31, 2020.

Based on economic conditions on December 31, 2020, our approved development plan provides for the development of our remaining PUD locations within five years of the date such reserves were initially recorded. As of December 31, 2020, our 2021 PUD reserve conversion rate is expected to be approximately 22 percent. The balance of the PUD reserves are scheduled to be developed over the remaining four years in accordance with our current development plan. The level of capital spending necessary to achieve this drilling schedule is consistent with our recent performance and our outlook for future development activities.

2019 Activity. During 2019, we increased proved reserves by 65.9 MMBoe, or 12 percent, relative to December 31, 2018. The increase in proved reserves was primarily a result of our 2019 development activities and our future drilling schedule. In 2019, we produced 49.4 MMBoe.

Revisions of Previous Estimates- Proved Developed Reserves. Proved developed reserves experienced a positive revision of 28.3 MMBoe reflecting improved performance revisions, decreased operating costs and other items. An additional increase of 10.2 MMBoe in developed reserves related to our current year drilling activities. These positive revisions were partially offset by a decrease of 11.0 MMBoe for decreases in prices for crude oil, natural gas and NGLs.

Revisions of Previous Estimates- PUDs. Upward revisions to our PUD reserves were related to an increase of 74.2 MMBoe reflecting additional locations on proven acreage resulting from our drilling plan, as well as improved performance revisions and other items, which resulted in further upward revisions of 28.9 MMBoe of PUD reserves. Partially offsetting these increases were negative revisions of 12.9 MMBoe due to drilling schedule changes and 5.5 MMBoe for decreases in prices for crude oil, natural gas and NGLs.

Extensions, Discoveries and Other Additions- Proved Developed Reserves. Developed activity for 2019 included the addition of 4.3 MMBoe of developed reserves related to three gross (three net) newly-drilled wells.

Extensions, Discoveries and Other Additions- PUDs. There were no extensions, discoveries or other additions for PUD reserves during 2019.

Acquisitions of Reserves- Proved Developed Reserves. Proved developed reserves acquired in various acreage exchanges and acquisitions were 0.4 MMBoe during 2019.

Acquisitions of Reserves- PUDs. We acquired 1.3 MMBoe of PUD reserves in 2019 in acreage exchanges and acquisitions.

Dispositions- Proved Developed Reserves. Dispositions of 0.5 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

Dispositions- PUDs. Dispositions of 2.4 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

2018 Activity. During 2018, we increased proved reserves by 92.0 MMBoe, or 20 percent, relative to December 31, 2017. The increase in proved reserves was primarily a result of acreage exchange transactions and acquisitions in the Wattenberg Field and reserve additions on proved acreage resulting from our 2018 development activities. In 2018, we produced 40.2 MMBoe.

Revisions of Previous Estimates- Proved Developed Reserves. Proved developed reserves experienced a net positive revision of 11.4 MMBoe due to an increase in prices for crude oil, natural gas and NGLs, offset by net negative revisions of 5.1 MMBoe for an increase in operating costs, performance revisions and other items.

Revisions of Previous Estimates- PUDs. Upward revisions to our PUD reserves were related to an increase of 71.7 MMBoe reflecting newly-booked locations on proven acreage resulting from our drilling activities. Partially offsetting this increase was a negative revision of 26.8 MMBoe in the Wattenberg Field due to drilling schedule changes and updated timing for development of certain locations exceeding the five-year rule. Drilling schedule changes, primarily related to 2018 acreage exchanges, resulted in these locations being reclassified from proved to unproved status. All other changes were due to commodity pricing, lease operating expenses and type curve revisions, which resulted in further upward revisions of 3.8 MMBoe of PUD reserves.

Extensions, Discoveries and Other Additions- Proved Developed Reserves. Developed additions for 2018 included the addition of 7.9 MMBoe of developed reserves related to 17 gross (9.2 net) newly-drilled wells.

Extensions, Discoveries and Other Additions- PUDs. PUD activity was comprised primarily of 20.1 MMBoe of PUD reserves related to 16 gross (15.0 net) PUD locations in the Delaware Basin.

Acquisitions of Reserves- Proved Developed Reserves. Proved developed reserves acquired in various acreage exchanges were 8.8 MMBoe during 2018.

Acquisitions of Reserves- PUDs. We acquired 47.6 MMBoe and 4.0 MMBoe of PUD reserves in 2018 in acreage exchanges and an acquisition, respectively.

Dispositions- Proved Developed Reserves. Dispositions of 4.5 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

Dispositions- PUDs. Dispositions of PUDs were 6.6 MMBoe reflecting divested proved acreage with future locations that were not in our five-year drilling plan as of December 31, 2017 in the acreage exchange transactions.

Results of Operations for Crude Oil and Natural Gas Producing Activities

The results of operations for crude oil and natural gas producing activities are presented below.

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Revenues:			
Crude oil, natural gas and NGLs sales	$ 1,152,555	$ 1,307,275	$ 1,389,961
Commodity price risk management gain (loss), net	180,270	(162,844)	145,237
	1,332,825	1,144,431	1,535,198
Expenses:			
Lease operating expenses	161,346	142,248	130,957
Production taxes	59,368	80,754	90,357
Transportation, gathering and processing expenses	77,835	46,353	37,403
Exploration expense	1,376	4,054	6,204
Depreciation, depletion and amortization	611,003	638,499	551,265
Accretion of asset retirement obligations	10,072	6,117	5,075
Impairment of properties and equipment	882,393	38,536	458,397
(Gain) loss on sale of properties and equipment	(724)	9,734	394
	1,802,669	966,295	1,280,052
Results of operations for crude oil and natural gas producing activities before provision for income taxes	(469,844)	178,136	255,146
Income tax (expense) benefit	5,168	(9,869)	(185,667)
Results of operations for crude oil and natural gas producing activities, excluding corporate overhead and interest costs	$ (464,676)	$ 168,267	$ 69,479

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including costs such as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance, production and severance taxes and associated administrative expenses. DD&A expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment. The provision for income taxes is computed using effective statutory tax rates.

Costs Incurred in Crude Oil and Natural Gas Activities

Costs incurred in crude oil and natural gas property acquisition, exploration and development are presented below.

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Acquisition of properties: (1)			
Proved properties	$ 1,618,000	$ 16,007	$ 205,253
Unproved properties	114,202	9,567	5,477
Development costs (2)	528,686	780,851	970,970
Exploration costs: (3)			
Exploratory drilling	12,892	32,218	36,704
Geological and geophysical	253	3,017	3,401
Total costs incurred	$ 2,274,033	$ 841,660	$ 1,221,805

(1) Property acquisition costs represent costs incurred to purchase, lease or otherwise acquire a property.

(2) Development costs represent costs incurred to gain access to and prepare development well locations for drilling, drill and equip development wells, recomplete wells and provide facilities to extract, treat, gather and store crude oil, natural gas and NGLs. Of these costs incurred for the years ended December 31, 2020, 2019 and 2018, $270.7 million, $308.9 million and $438.4 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end. These costs also include approximately, $35.3 million and $74.6 million of infrastructure and pipeline costs in 2019 and 2018 respectively. Our infrastructure and pipeline assets were divested in 2019.

(3) Exploration costs represent costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing crude oil, natural gas and NGLs. These costs include, but are not limited to, dry hole contributions and costs of drilling and equipping exploratory wells.

Capitalized Costs Related to Crude Oil and Natural Gas Producing Activities

Aggregate capitalized costs related to crude oil and natural gas exploration and production activities with applicable accumulated DD&A are presented below as of the dates indicated:

	December 31,	
	2020	2019
	(in thousands)	
Proved crude oil and natural gas properties	$ 7,523,639	$ 6,241,780
Unproved crude oil and natural gas properties	350,677	403,379
Uncompleted wells, equipment and facilities	523,376	382,409
Capitalized costs	8,397,692	7,027,568
Accumulated DD&A	(3,590,932)	(2,982,929)
Capitalized costs, net	$ 4,806,760	$ 4,044,639

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves

The standardized measure below has been prepared in accordance with U.S. GAAP. Future estimated cash flows were based on a 12-month average price calculated as the unweighted arithmetic average of the prices on the first day of each month, January through December, applied to our year-end estimated proved reserves. Prices for each of the three years were adjusted by field for Btu content, transportation and regional price differences; however, they were not adjusted to reflect the value of our commodity derivatives. Production and development costs were based on prices as of December 31 for each of the respective years presented. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service or to depreciation, depletion and amortization expense. Production and development costs include those cash flows associated with the expected ultimate settlement of our asset retirement obligations. Future estimated income tax expense is computed by applying the statutory rate in effect at the end of each year to the projected future pre-tax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

The following table presents information with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Changes in the demand for crude oil, natural gas and NGLs, inflation and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of our proved reserves.

	December 31,		
	2020	2019	2018
		(in thousands)	
Future estimated cash flows	$ 12,481,830	$ 14,590,604	$ 17,554,880
Future estimated production costs [1]	(4,209,459)	(4,530,173)	(4,782,948)
Future estimated development costs	(2,337,806)	(3,257,106)	(3,632,822)
Future estimated income tax expense	(301,507)	(907,382)	(1,404,121)
Future net cash flows	5,633,058	5,895,943	7,734,989
10% annual discount for estimated timing of cash flows	(2,350,879)	(2,585,609)	(3,287,273)
Standardized measure of discounted future estimated net cash flows	$ 3,282,179	$ 3,310,334	$ 4,447,716

(1) Represents future estimated lease operating expenses, production taxes and transportation, gathering and processing expenses.

The following table presents the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Beginning of period	$ 3,310,334	$ 4,447,716	$ 2,880,105
Sales of crude oil, natural gas and NGLs production, net of production costs	(854,006)	(1,037,920)	(1,131,244)
Net changes in prices and production costs [1]	(1,771,019)	(2,122,538)	936,077
Extensions, discoveries and improved recovery, less related costs	14,110	39,606	190,084
Sales of reserves	(26,771)	(14,533)	(42,362)
Purchases of reserves	1,969,846	18,816	467,807
Development costs incurred during the period	329,495	605,753	462,088
Revisions of previous quantity estimates	(775,009)	538,242	631,198
Changes in estimated income taxes	354,369	346,826	(232,002)
Net changes in future development costs	367,630	206,003	(123,663)
Accretion of discount	572,483	532,127	583,744
Timing and other	(209,283)	(249,764)	(174,116)
End of period	$ 3,282,179	$ 3,310,334	$ 4,447,716

(1) Our weighted-average price, net of production costs per Boe, in our 2020 reserve report decreased to $11.32 as compared to $16.18 for 2019 and $23.44 for 2018.

The data presented should not be viewed as representing the expected cash flows from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the recent average prices and current costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

QUARTERLY FINANCIAL INFORMATION - UNAUDITED

Quarterly financial data for the years ended December 31, 2020 and 2019 is presented below. The sum of the quarters may not equal the total of the year's net income or loss per share due to changes in the weighted-average shares outstanding throughout the year.

	2020			
	Quarter Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share data)			
Total revenues	$ 757,030	$ 54,416	$ 249,217	$ 278,563
Total costs, expenses and other	1,205,617	250,393	258,802	267,952
Income (loss) from operations	(448,587)	(195,977)	(9,585)	10,611
Income (loss) before income taxes	(472,760)	(217,759)	(30,607)	(11,096)
Net income (loss)	$ (465,015)	$ (221,832)	$ (30,783)	$ (6,690)
Loss per share:				
Basic	$ (4.94)	$ (2.23)	$ (0.31)	$ (0.07)
Diluted	(4.94)	(2.23)	(0.31)	(0.07)

	2019			
	Quarter Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share data)			
Total revenues	$ 134,500	$ 390,658	$ 365,943	$ 265,022
Total costs, expenses and other	275,120	280,623	321,562	267,713
Income (loss) from operations	(140,620)	110,035	44,381	(2,691)
Income (loss) before income taxes	(157,588)	91,135	26,570	(20,111)
Net income (loss)	$ (120,176)	$ 68,548	$ 15,908	$ (20,952)
Earnings (loss) per share:				
Basic	$ (1.82)	$ 1.04	$ 0.25	$ (0.34)
Diluted	(1.82)	1.04	0.25	(0.34)

FINANCIAL STATEMENT SCHEDULE

Schedule II -VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1,	Charged to Costs and Expenses	Deductions [1]	Ending Balance December 31,
		(in thousands)		
2020:				
Allowance for doubtful accounts	$ 7,476	$ 3,179	$ 3,892	$ 6,763
Allowance for expirations of unproved crude oil and natural gas properties	6,881	223,895	6,757	224,019
2019:				
Allowance for doubtful accounts	$ 4,381	$ 3,209	$ 114	$ 7,476
Allowance for expirations of unproved crude oil and natural gas properties	542,709	8,523	544,351	6,881
2018:				
Allowance for doubtful accounts	$ 3,128	$ 1,276	$ 23	$ 4,381
Allowance for expirations of unproved crude oil and natural gas properties	251,159	388,068	96,518	542,709

(1) For allowance for doubtful accounts, deductions represent the write-off of accounts receivable deemed uncollectible. For allowance for expirations of unproved crude oil and natural gas properties, deductions represent actual expired or abandoned unproved crude oil and natural gas properties, with a corresponding decrease to the historical cost of the associated asset.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2020, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. Based on the results of this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2020.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, and effected by our board of directors, management and other personnel 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.

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 policies or procedures may deteriorate.

Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2020, based upon the criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2020.

The effectiveness of our internal control over financial reporting as of December 31, 2020 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2021 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 11. EXECUTIVE COMPENSATION

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2021 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2021 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2021 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2021 Annual Stockholders' meeting and is incorporated by reference in this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Exhibits:

See Exhibits Index on the following page.

ITEM 16. FORM 10-K SUMMARY

None.

Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
2.1	Plan of Conversion, dated June 5, 2015, by PDC Energy, Inc.	8-K12B	001-37419	2.1	6/8/2015	
2.2	Agreement and Plan of Merger, dated as of August 25, 2019 by and between PDC Energy, Inc., and SRC Energy Inc.	8-K	001-37419	2.2	8/26/2019	
3.1	Certificate of Incorporation of PDC Energy, Inc., as amended.	8-K12B	001-37419	3.1	5/27/2020	
3.2	Bylaws of PDC Energy, Inc.	8-K12B	001-37419	3.2	6/8/2015	
4.1	Description of Capital Stock					X
4.2	Form of Common Stock Certificate of PDC Energy, Inc.	10-K	001-37419	4.1.1	2/26/2020	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.3	Indenture, dated as of November 29, 2017, by and between PDC Energy, Inc., PDC Permian, Inc., a subsidiary guarantor of PDC Energy, Inc., and U.S. Bank Trust National Association, as Trustee, relating to the 5.750% Senior Notes due 2026.	8-K	001-37419	4.1	11/29/2017	
4.4	Base Indenture, dated as of September 14, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust National Association, as Trustee.	8-K	001-37419	4.1	9/14/2016	
4.5	First Supplemental Indenture, dated as of September 14, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust National Association, as Trustee, relating to the 1.125% Convertible Senior Notes due 2021.	8-K	001-37419	4.2	9/14/2016	
4.7	Indenture, dated as of September 15, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust National Association, as Trustee, relating to the 6.125% Senior Notes due 2024.	8-K	001-37419	4.1	9/15/2016	
4.8	Indenture, dated as of November 29, 2017, among SRC Energy, Inc. and U.S. Bank National Association as Trustee, relating to the SRC Energy, Inc. 6.250% Senior Notes due 2025.	8-K	001-37419	4.1	11/29/2017	
4.9	First Supplemental Indenture, dated as of January 14, 2020, among PDC Energy, Inc. and U.S. Bank National Association as Trustee, related to the SRC Energy, Inc. 6.250% Senior Notes due 2025.	8-K	001-37419	4.2	1/14/2019	
10.1	Form of Indemnification Agreement.	8-K	000-07246	10.1	6/8/2015	
10.2	401(k) and Profit Sharing Plan, as amended on January 4, 2016.	10-K	001-37419	10.2	2/28/2017	
10.3	Amended and Restated Non-Employee Director Deferred Compensation Plan.	10-K	001-37419	10.3	2/27/2018	
10.4	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008 ("2004 Plan").	10-K	000-07246	10.26	2/27/2009	
10.5	Summary of 2010 Stock Appreciation Rights and Restricted Stock Awards under the 2004 Plan.	8-K	000-07246		4/23/2010	
10.6	Amended and Restated 2010 Long-Term Equity Compensation Plan, as amended.	10-K	001-37419	10.5	2/22/2016	
10.7	Executive Severance Compensation Plan, as amended and restated.	10-Q	001-37419	10.1	8/6/2020	
10.8	Form of 2011 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.2	2/21/2014	
10.9	Form of 2013 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.10	2/27/2013	
10.10	Form of 2014 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.5	2/19/2015	
10.11	Form of 2015 Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.8	2/19/2015	
10.12	Form of 2019 Performance Share Agreement.	10-Q	001-37419	99.1	5/2/2019	
10.14	Form of 2019 Restricted Stock Unit Agreement (Directors).	10-Q	001-37419	99.2	5/2/2019	
10.15	Form of 2019 Restricted Stock Unit Agreement (Executives) (Amended and Restated 2010 Long-Term Equity Compensation Plan).	10-Q	001-37419	99.3	5/2/2019	
10.16	Form of 2019 Restricted Stock Unit Agreement (Executives) (2018 Equity Incentive Plan).	10-Q	001-37419	99.4	5/2/2019	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
10.17	SRC Energy, Inc./PDC Energy, Inc. Merger Performance Share Agreement, dated January 13, 2020, by and between PDC Energy, Inc.(as successor to SRC Energy, Inc.) and Lynn A. Peterson.	8-K	001-37419	10.2	1/14/2020	
10.18	Form of 2020 Performance Share Agreement.	10-Q	001-37419	99.1	5/7/2020	
10.19	Form of 2020 Restricted Stock Unit Agreement (Executives).	10-Q	001-37419	99.3	5/7/2020	
10.20	Form of 2020 Restricted Stock Unit Agreement (Directors).	10-Q	001-37419	99.2	5/7/2020	
10.21	Employment Agreement with Lance A. Lauck, as amended.	10-Q	001-37419	10.2	8/6/2020	
10.22	2018 Equity Incentive Plan.	8-K	001-37419	10.1	5/31/2018	
10.23	Amendment No. 1 to PDC Energy, Inc. 2018 Equity Incentive Plan.	8-K	001-37419	10.1	5/27/2020	
10.24	SRC Energy Inc. 2015 Equity Incentive Plan.	8-K	001-37419	10.1	1/14/2020	
10.25	Fourth Amended and Restated Credit Agreement, dated as of May 23, 2018, among PDC Energy, Inc. as Borrower, each of the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent for the Lenders.	8-K	001-37419	10.1	5/25/2018	
10.26	First Amendment to Fourth Amended and Restated Credit Agreement, dated as August 30, 2019, among PDC Energy, Inc. as Borrower, each of the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent for the Lenders.	8-K	001-37419	10.1	9/4/2019	
10.27	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of May 5, 2020 among PDC Energy, Inc. as Borrower, each of the Lenders party thereto, and JPMorgan Chase Bank, N.A. as administrative Agent for the Lenders.	10-Q	001-37419	10	5/7/2020	
21.1	Subsidiaries.	10-K	001-37419	21.1	2/26/2020	
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Ryder Scott Company, L.P., Petroleum Consultants.					X
23.3	Consent of Netherland, Sewell & Associates, Inc., Petroleum Consultants.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1*	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
99.1	Report of Independent Petroleum Consultants - Ryder Scott Company, L.P.					X
99.2	Report of Independent Petroleum Consultants - Netherland, Sewell & Associates, Inc.					X
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)					X

* Furnished herewith.

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.

PDC ENERGY, INC.

By: /s/ Barton Brookman
Barton Brookman
President and Chief Executive Officer

February 24, 2021

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:

Signature	Title	Date
/s/ Barton Brookman Barton Brookman	President, Chief Executive Officer and Director (principal executive officer)	February 24, 2021
/s/ R. Scott Meyers R. Scott Meyers	Senior Vice President and Chief Financial Officer (principal financial officer)	February 24, 2021
/s/ Douglas Griggs Douglas Griggs	Chief Accounting Officer (principal accounting officer)	February 24, 2021
/s/ Mark E. Ellis Mark E. Ellis	Chairman and Director	February 24, 2021
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	February 24, 2021
/s/ Christina M. Ibrahim Christina M. Ibrahim	Director	February 24, 2021
/s/ Paul J. Korus Paul J. Korus	Director	February 24, 2021
/s/ Randy S. Nickerson Randy S. Nickerson	Director	February 24, 2021
/s/ David C. Parke David C. Parke	Director	February 24, 2021
/s/ Lynn A. Peterson Lynn A. Peterson	Director	February 24, 2021

GLOSSARY OF UNITS OF MEASUREMENT AND INDUSTRY TERMS

UNITS OF MEASUREMENT

The following presents a list of units of measurement used throughout the document.

Bbl – One barrel of crude oil or NGL or 42 gallons of liquid volume.
Bcf – One billion cubic feet of natural gas volume.
Boe – One barrel of crude oil equivalent.
Btu – British thermal unit.
BBtu – One billion British thermal units.
MBoe – One thousand barrels of crude oil equivalent.
MBbls – One thousand barrels of crude oil.
Mcf – One thousand cubic feet of natural gas volume.
MMBoe – One million barrels of crude oil equivalent.
MMBbls – One million barrels of crude oil.
MMBtu – One million British thermal units.
MMcf – One million cubic feet of natural gas volume.
MMcfd – One million cubic feet of natural gas volume per day.

GLOSSARY OF INDUSTRY TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report:

Brent - Brent sweet light crude oil.

CIG - Colorado Interstate Gas.

Completion - Refers to the installation of permanent equipment for the production of crude oil and natural gas from a recently drilled well or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Condensate - Liquid hydrocarbons associated with the production that is primarily natural gas.

Developed acreage - Acreage assignable to productive wells.

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.

Differentials - The difference between the crude oil and natural gas index spot price and the corresponding cash spot price in a specified location.

Dry well or dry hole - A well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion as an oil or gas well.

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.

Extensions, discoveries and other additions - As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

Farm-out - Transfer of all or part of the operating rights from a working interest owner to an assignee, who assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty interest but may retain any type of interest.

Fracture or *Fracturing* - Procedure to stimulate production by forcing a mixture of fluid and proppant into the formation under high pressure. Fracturing creates artificial fractures in the reservoir rock to increase permeability and porosity, thereby allowing the release of trapped hydrocarbons.

Gross acres or *wells* - Refers to the total acres or wells in which we have a working interest.

Henry Hub - Refers to the pricing point for natural gas futures contracts traded on NYMEX.

Horizontal drilling - A drilling technique that permits the operator to drill a horizontal well shaft from the bottom of a vertical well and thereby to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Joint interest billing - Process of billing/invoicing the costs related to well drilling, completions and production operations among working interest partners.

Natural gas liquid(s) or *NGL(s)* - Hydrocarbons which can be extracted from natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs include ethane, propane, butane and other natural gasolines.

Net acres or *wells* - Refers to gross acres or wells we own multiplied, in each case, by our percentage working interest.

Net production - Crude oil and natural gas production that we own, less royalties and production due to others.

Non-operated - A project in which we are not the operator.

NYMEX - New York Mercantile Exchange.

Operator - The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

Overriding royalty - An interest which is created out of the operating or working interest. Its term is coextensive with that of the operating interest.

Possible reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability to exceed the sum of proved, probable and possible reserves. When probabilistic methods are used, there must be at least a 10 percent probability that the actual quantities recovered will equal or exceed the sum of proved, probable and possible estimates.

Present value of future net revenues or *(PV-10)* - The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, of proved reserves calculated in accordance with Financial Accounting Standards Board guidelines, net of estimated production and future development costs, using pricing and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization and discounted using an annual discount rate of 10 percent. PV-10 is pre-tax and therefore a non-U.S. GAAP financial measure.

Probable reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Similarly, when probabilistic methods are used, there must be at least a 50 percent probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Productive well - An exploratory or developmental well that is not a dry well or dry hole, as defined above.

Proved developed non-producing reserves - Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and/or

(ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves or *PDPs* - Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves - The combination of proved developed producing and proved developed non-producing reserves.

Proved reserves - This term means "proved oil and gas reserves" as defined in SEC Regulation S-X Section 4-10(a) and refers to those quantities of crude oil and condensate, natural gas and NGLs, 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 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.

Proved undeveloped reserves or *PUDs* - 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.

Recomplete or *Recompletion* - The modification of an existing well for the purpose of producing crude oil and natural gas from a different producing formation.

Reserves - Estimated remaining quantities of crude oil, natural gas, NGLs and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering crude oil, natural gas and NGLs or related substances to market, and all permits and financing required to implement the project.

Royalty - An interest in a crude oil and natural gas lease or mineral interest that gives the owner of the royalty the right to receive a portion of the production from the leased acreage or mineral interest (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Spud - To begin drilling; the act of beginning a hole.

Standardized measure of discounted future net cash flows or *standardized measure* - Future net cash flows discounted at a rate of 10 percent. Future net cash flows represent the estimated future revenues to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment and (ii) future income tax expense.

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

Undeveloped acreage - Leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas, regardless of whether such acreage contains proved reserves.

Waha - Waha West Texas natural gas prices

Working interest - An interest in a crude oil and natural gas lease that gives the owner of the interest the right to drill and produce crude oil and natural gas on the leased acreage. It requires the owner to pay its share of the costs of drilling and production operations.

Workover - Major remedial operations on a producing well to restore, maintain, or improve the well's production.